S. Hag. 102-57

IMPLICATIONS OF PROPOSED NATIONAL ENERGY POLICY LEGISLATION FOR NATURAL GAS

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY REGULATION AND CONSERVATION

OF THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDRED SECOND CONGRESS

FIRST SESSION

ON

S. 341 (Title X)

TO REDUCE THE NATION'S DEPENDENCE ON IMPORTED OIL, TO PROVIDE FOR THE ENERGY SECURITY OF THE NATION AND FOR OTHER PURPOSES

S. 570 (Title II)

TO IMPLEMENT THE NATIONAL ENERGY STRATEGY, AND FOR OTHER PURPOSES

S. 662

TO INCREASE THE USE OF NATURAL GAS IN THE UNITED STATES

DENVER, CO, APRIL 3, 1991

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S311-50

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IMPLICATIONS OF PROPOSED NATIONAL ENERGY POLICY LEGISLATION FOR NATURAL GAS

WEDNESDAY, APRIL 3, 1991

U.S. SENATE,
SUBCOMMITTEE ON ENERGY REGULATION
AND CONSERVATION,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Denver, CO.

The subcommittee met, pursuant to notice, at 9:30 a.m. in room 450, City and County Building, Hon. Timothy E. Wirth, presiding.

OPENING STATEMENT OF HON. TIMOTHY E. WIRTH, U.S. SENATOR FROM COLORADO

Senator WIRTH. The committee will come to order. The Senate is privileged to be in Denver, Colorado, today to hear testimony on an issue of great importance to the country and to the State of Colorado: the increase in our capacity to use our enormous reserves of natural gas.

Two events over the last 4 months certainly remind us of the importance of natural gas and energy independence. The first of those is clearly the set of issues surrounding the American presence in the Persian Gulf. If there is any lesson to be drawn from the Persian Gulf, it is certainly that we do not want that to happen again. We do not want ourselves to be in such a position of extraordinary dependence upon imported oil.

The opportunity's available with natural gas to back out imported oil, to develop a resource that is not only domestic, but is also cheap and clean, presents to us a win-win-win situation, an unusual situation for anybody in public office in 1991.

Second, we are reminded by the shutdowns of various energy operations on the Western Slope, capped by the Unocal decision last week, of how fragile our economy is and how our economy is, in fact, dependent upon energy reserves. The State of Colorado sits on top of very significant reserves of natural gas. The second largest reserves in the country are in the Rocky Mountain region, after the Gulf Coast.

The natural gas industry is among the top ten in the State of Colorado in terms of employment and payroll and has potential to take up much of the slack that was left through the shutdown of Unocal. So it is my pleasure this morning to be able to chair this hearing. I want to thank Mr. Don Santa, counsel for the Energy and Natural Resources Committee, for coming to Denver today.

[The prepared statement of Senator Wirth and the texts of the bills follow:]

PREPARED STATEMENT OF HON. TIMOTHY E. WIRTH, U.S. SENATOR FROM COLORADO

This is a field hearing of the Subcommittee on Energy Regulation and Conservation of the United States Senate Committee on Energy and Natural Resources. The topic of today's hearing is the implications of proposed national energy policy legislation for natural gas production and consumption in the United States.

The Energy Committee will begin marking up energy policy legislation when it returns from recess. There is universal agreement natural gas can play a pivotal role in the energy policy that will emerge from the legislative process. Yet, despite the widespread support for greater utilization of natural gas, this fuel is something of an enigma.

Our Nation is blessed with an abundant natural gas resource base. Our Nation has a well developed natural gas delivery system of gathering lines, interstate pipelines and local distribution companies. Natural gas is the cleanest of fossil fuels. It can be utilized in a variety of applications to promote a cleaner environment and the displacement of imported oil.

Yet, despite all of these virtues, the Nation is consuming approximately 20 percent less natural gas than it did 20 years ago. Not only is consumption down, but so is price. In real dollars, natural gas prices both at the wellhead and at the city gate are at all-time lows. A week ago, spot market wellhead prices for Rocky Mountain natural gas were less than $1.00 per million Btus. Furthermore, natural gas sells at a substantial discount to competing fuels. On a delivered-to-the-market basis, natural gas sells at a 60 percent discount to heating oil and a 25 percent discount to residual fuel oil.

What we can do about the enigma of natural gas is to change the law to promote the development of enhanced natural gas markets and promote the more efficient delivery of natural gas to those markets. The Energy Committee's pending business includes several bills that are intended, in part, to do just that.

Among these energy bills are several that I authored with the able assistance of some of today's witnesses. The Energy Committee's Chairman, Senator Bennett Johnston of Louisiana, has said that it is his goal to have a "Made in America" energy policy. We would like to do our part with a "Made in Colorado" natural gas policy. This policy is embodied in S. 662, the Natural Gas Policy Reform Act. The same natural gas provisions are part of the comprehensive energy policy legislation that I introduced on March 21, S. 741, the National Energy Efficiency and Development Act of 1991.

Our "Made in Colorado" natural gas policy is the product of the leader's of our State's natural gas industry. Last year, I asked them to sit down, put aside their differences, and decide how best to promote the increased use of natural gas. They did just that, and their recommendations to me are incorporated in S. 662 and S. 741.

The leaders of this industry effort deserve special recognition. First, Public Service Company of Colorado, our state's largest gas distributor. Second, Colorado Interstate Gas, one of our major interstate pipeline companies. Third, the Independent Petroleum Association the Mountain States, representing our region's independent producers.

I look forward to today's testimony from our panel of distinguished witnesses and from the United States Department of Energy.

II

102D CONGRESS
1ST SESSION

S. 341

To reduce the Nation's dependence on imported oil, to provide for the energy security of the Nation and for other purposes.

IN THE SENATE OF THE UNITED STATES

FEBRUARY 5 (legislative day, JANUARY 3), 1991

Mr. JOHNSTON (for himself and Mr. WALLOP) introduced the following bill; which was read twice and referred to the Committee on Energy and Natural Resources

---

A BILL

To reduce the Nation's dependence on imported oil, to provide for the energy security of the Nation and for other purposes.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

That this Act may be referred to as the "National Energy Security Act of 1991".

* * * * * * *

TITLE X—NATURAL GAS

SEC. 10001. OPTIONAL PROCEDURES FOR THE CONSTRUCTION OF NATURAL GAS FACILITIES.

(a) DEFINITIONS.—For the purposes of this section the term—

(1) "Commission" means the Federal Energy Regulatory Commission;

(2) "transportation service" means the transportation in interstate commerce of natural gas by a natural-gas company for itself or any other person;

(3) "rate schedule" means a statement of a rate or charge for a particular classification of transportation in interstate commerce of natural gas, and all terms, conditions, classifications, practices, rules and regulations affecting such rate or charge.

(4) "rate" means a rate or charge demanded or received for a particular classification of transportation in interstate commerce of natural gas, and all terms,

conditions, classifications, practices, rules and regulations affecting such rate or charge.

(b) CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY.—

(1) CONSTRUCTION.—For the purposes of section 7 of the Natural Gas Act, a certificate of public convenience and necessity is not required for the construction of a facility to provide transportation service: *Provided*, That the construction of such facility commences after the date of enactment of the National Energy Security Act of 1991.

(2) OPERATION.—Upon the initiation of transportation service rendered by a facility constructed pursuant to paragraph (1), the Commission, pursuant to its authority under section 7 of the Natural Gas Act, shall immediately issue a certificate of public convenience and necessity for such transportation service. The natural-gas company shall accept the certificate. The certificate shall include such reasonable terms and conditions as the public convenience and necessity may require.

(c) RATE SCHEDULES; BOOKS, ACCOUNTS AND RECORDS, AND RATE REVISIONS.—

(1) RATE SCHEDULES.—

(i) Prior to initiating transportation service utilizing a facility constructed pursuant to paragraph (b)(1), the natural-gas company shall file with the Commission the rate schedule for such facility.

(ii) The natural-gas company shall keep in convenient form and place and make open for public inspection the rate schedule for such facility.

(iii) An agreement between the natural-gas company and a person, including itself, who contracts for transportation service to be rendered utilizing such facility, may constitute a rate schedule: *Provided*, That such agreement is inclusive of all data and information required to be set forth in a rate schedule.

(iv) The rate for a facility constructed pursuant to paragraph (b)(1) shall be established on a stand-alone and incremental basis.

(2) BOOKS, ACCOUNTS AND RECORDS.—A natural-gas company that constructs a facility pursuant to paragraph (b)(1) shall maintain a separate system of books, accounts and records for such facility.

(3) RATE REVISIONS.—

(i) Upon its own motion or upon a complaint by any person, the Commission shall review the rate for a facility constructed pursuant to paragraph (b)(1) to ascertain whether there is a reasonable basis to conclude that such rate may be unjust, unreasonable, unduly discriminatory or preferential within the meaning of the Natural Gas Act.

(ii) If, as a result of such review, the Commission determines that there is a reasonable basis to conclude that such rate may be unjust, unreasonable, unduly discriminatory or preferential, pursuant to its authority under section 5 of the Natural Gas Act the Commission shall initiate a proceeding to determine if the rate is unjust, unreasonable, unduly discriminatory or preferential within the meaning of the Natural Gas Act.

(iii) If, as a result of the proceeding initiated under section 5 of the Natural Gas Act, the Commission finds that such rate is unjust, unreasonable, unduly discriminatory or preferential within the meaning of the Natural Gas Act, pursuant to its authority under section 5 of the Natural Gas Act the Commission shall determine the just and reasonable rate, charge, classification rule, regula-

tion, practice, or contract to be thereafter observed and in force, and shall fix the same by order.

(d) RATE BASE TREATMENT.—A natural-gas company may not, for ten years subsequent to the date on which a facility constructed pursuant to paragraph (b)(1) was placed into service, allocate the costs incurred for the construction, operation or maintenance of such facility to any other service rendered by such company.

(e) OTHER LAWS.—Except as expressly provided in this section, facilities constructed under authority of paragraph (b)(1) shall be subject to all applicable federal and state laws.

SEC. 10002. TRANSPORTATION OF NATURAL GAS UNDER THE NGPA.

Section 311 of the Natural Gas Policy Act of 1978 (15 U.S.C. 3371) is amended by—

(a) striking "AUTHORIZATION OF CERTAIN SALES AND TRANSPORTATION" and inserting in lieu thereof "AUTHORIZATION OF CERTAIN SALES, TRANSPORTATION AND CONSTRUCTION";

(b) striking "Commission Approval of Transportation" and inserting in lieu thereof "Commission Approval of Transportation and Construction"; and by

(c) striking paragraph 311(a)(1), and inserting in lieu thereof the following:

"(1) INTERSTATE PIPELINES.—

"(A) TRANSPORTATION.—The Commission may, by rule or order, authorize any interstate pipeline to transport natural gas on behalf of any other person.

"(B) CONSTRUCTION.—The Commission may, by rule or order, authorize the construction of facilities to transport natural gas in interstate commerce pursuant to subparagraph (A).

"(C) JUST AND REASONABLE RATES.—The rates and charges of any interstate pipeline with respect to any transportation authorized under subparagraph (A) shall be just and reasonable (within the meaning of the Natural Gas Act).

"(D) NON-DISCRIMINATORY TRANSPORTATION.—Any transportation authorized under subparagraph (A) shall not be unjust, unreasonable, unduly discriminatory or preferential (within the meaning of the Natural Gas Act).".

SEC. 10003. NEPA COMPLIANCE.

(a) LEAD AGENCY.—In cases where Federal Energy Regulatory Commission authorization of the construction or operation of facilities or projects under the Natural Gas Act

or the Federal Power Act may be deemed a major Federal action under the National Environmental Policy Act or requires the preparation of other environmental documents, the Commission shall be the lead agency and shall have primary authority for compliance with section 2 and title I of the National Environmental Policy Act. The Commission may set reasonable time limits for consultation with other Federal agencies which participate in the review of a proposed facility or project pursuant to the National Environmental Policy Act to complete their review of any potential environmental impacts of the construction or operation of such facility or project, and for such other agencies to consult and submit comments to the Commission.

(b) ENVIRONMENTAL DOCUMENTS.—Where environmental documents are prepared in connection with applications for authority to construct or operate facilities or projects under the Natural Gas Act or the Federal Power Act, the Federal Energy Regulatory Commission shall permit, at the election of the applicant, a contractor, consultant or other person funded by the applicant to prepare such environmental document. The contractor shall be chosen by the Commission in its sole discretion. The Commission shall establish procedures to assure that the contractor, consultant or other person has no financial or other potential conflict of interest in the outcome of the proceeding. Nothing herein shall affect

the Commission's responsibility to comply with the National Environmental Policy Act.

SEC. 10004. RATES AND CHARGES.

(a) NOTICE OF CHANGES.—The first and third sentences of section 4(d) of the Natural Gas Act (17 U.S.C. 717c(d)) are amended by striking "thirty days' notice" and inserting in lieu thereof "sixty days' notice".

(b) REFUNDS OF OVERCHARGES.—The third and fourth sentences of section 4(e) of the Natural Gas Act (17 U.S.C. 717c(e)) are amended to read as follows: "Where changes in rates or charges are thus made effective, the Commission may, by order, require the natural-gas company to furnish a bond, to be approved by the Commission, to refund any amounts ordered by the Commission, to keep accurate accounts in detail of all amounts received by reason of such changes, specifying by whom and in whose behalf such amounts were paid, and, upon completion of the hearing and decision, to order the natural-gas company to refund, with interest, the portion of such rates or charges by its decision found to be not justified. At any hearing involving a rate or charge sought to be changed, the burden of proof to show that the changed rate or charge is just and reasonable shall be upon the natural-gas company, and the Commission shall give to the hearing and decision of such questions preference

over other questions pending before it and decide the same as speedily as possible.".

SEC. 10005. UTILIZATION OF RULEMAKING PROCEDURES.

The first sentence of section 403(c) of the Department of Energy Organization Act (42 U.S.C. 7173(c)) is amended to read as follows: "Any function described in section 402 of this Act which relates to the establishment of rates and charges under the Federal Power Act or to the establishment of rates and charges, the issuance of a certificate of public convenience and necessity, or the abandonment of facilities and services under the Natural Gas Act may be conducted by rulemaking procedures.".

SEC. 10006. REVIEW OF COMMISSION ORDERS.

(a) NATURAL GAS ACT AMENDMENTS.—

(1) REHEARING.—Section 19(a) of the Natural Gas Act (15 U.S.C. 717r(a)) is amended by striking "Unless the Commission acts upon the application for rehearing within thirty days after it is filed, such application may be deemed to have been denied." and inserting in lieu thereof "Unless the Commission issues a final order on the application for rehearing within sixty days after it is filed, such application shall be deemed denied: Provided, That the Commission may, for extraordinary cause, extend the period for rehearing an additional sixty days.".

(2) COURT REVIEW.—Section 19(b) of the Natural Gas Act (15 U.S.C. 717r(b)) is amended by striking the first through third sentences and inserting the following in lieu thereof: "Any party to a proceeding under this Act aggrieved by an order issued by the Commission in such proceeding may obtain a review of such order in the circuit court of appeals of the United States for any circuit wherein the natural-gas company to which the order relates is located or has its principal place of business, or in the United States Court of Appeals for the District of Columbia, by filing in such court, within thirty days after the order of the Commission upon the application for rehearing, a written petition praying that the order of the Commission be modified or set aside in whole or in part. The petition shall set forth specifically the ground or grounds upon which such petition is based. A copy of such petition shall forthwith be transmitted by the clerk of the court to the chairman of the Commission and thereupon the Commission shall file with the court the record upon which the order complained of was entered, as provided in section 2112 of title 28, United States Code.".

(b) NATURAL GAS POLICY ACT AMENDMENTS.—

(1) REHEARING.—Section 506(a)(2) of the Natural Gas Policy Act of 1978 (15 U.S.C. 3416(a)(2)) is

amended by striking "Unless the Commission acts upon such application for rehearing within thirty days after it is filed, such application shall be deemed to have been denied." and inserting in lieu thereof "Unless the Commission issues a final order on the application for rehearing within sixty days after it is filed, such application shall be deemed denied: *Provided*, That the Commission may, for extraordinary cause, extend the period for rehearing an additional sixty days.".

(2) COURT REVIEW.—Section 506(a)(4) of the Natural Gas Policy Act (15 U.S.C. 3416(a)(4)) is amended by striking the first through third sentences and inserting the following in lieu thereof: "Any person who is a party to a proceeding under this Act aggrieved by any final order issued by the Commission in such proceeding may obtain review of such order in the United States Court of Appeals for any circuit in which the party to which such order relates is located or has its principal place of business, or in the United States Court of Appeals for the District of Columbia circuit. Review shall be obtained by filing a written petition, requesting that such order be modified or set aside in whole or in part, in such Court of Appeals within thirty days after the final action of the Commis-

sion on the application for rehearing required under paragraph (2). The petition shall set forth specifically the ground or grounds upon which such petition is based. A copy of such petition shall forthwith be transmitted by the clerk of the court to the chairman of the Commission and thereupon the Commission shall file with the court the record upon which the order complained of was entered, as provided in section 2112 of title 28, United States Code.".

SEC. 10007. LIMITED ANTITRUST RELIEF FOR INDEPENDENT GAS PRODUCER COOPERATIVES.

(a) DEFINITIONS.—For the purposes of this section, the term—

(1) "antitrust laws" shall mean the Federal laws defined in section 2(37) of the Natural Gas Policy Act of 1978;

(2) "independent producer" means any person whose natural gas production does not exceed six million cubic feet per day: *Provided*, That any person who is an interstate pipeline, intrastate pipeline or local distribution company, as defined in sections 2(15), (16), and (17) of the Natural Gas Policy Act of 1978, or who is an affiliate of such person, as defined in section 2(27) of the Natural Gas Policy Act of 1978, may not

be considered an independent producer for the purposes of this section;

(3) "independent producer cooperative" shall mean any group of independent producers formed and operated for the purpose of pooling natural gas to enable the cooperative members to bargain effectively for the sale of the natural gas to any person: *Provided*, That such group is not formed or operated for the purpose of raising prices.

(b) LIMITED ANTITRUST RELIEF.—

(1) In any civil action under the antitrust laws, the formation or operation of an independent producer cooperative shall not be deemed illegal per se, but shall be illegal only if the anticompetitive effects substantially outweigh the procompetitive effects.

(2) Nothing in this section shall affect the ability of the United States, any State or a private party from obtaining an injunction against an independent producer cooperative for conduct that is proven to be illegal under the standard set forth in paragraph (1).

SEC. 10008. VEHICULAR NATURAL GAS JURISDICTION.

(a) DEFINITIONS.—For the purposes of this section—

(1) the term "VNG" means natural gas for ultimate use as a fuel in a motor vehicle, and includes compressed natural gas.

(2) the term "Motor Vehicle" includes any automobile, truck, bus, van, or other on-road or off-road motor vehicle, including a boat.

(b) PERSONS WITH HINSHAW EXEMPTIONS.—

(1) PLACE OF ULTIMATE CONSUMPTION.—For purposes of section 1(c) of the Natural Gas Act, in the case of any sale of VNG, such VNG shall be deemed to be "ultimately consumed" within the State in which physical delivery of such VNG occurs, whether or not physical combustion of such VNG occurs in another State.

(2) STATE REGULATION.—For purposes of section 1(c) of the Natural Gas Act, certification from a State commission to the Federal Energy Regulatory Commission that such State commission has regulatory jurisdiction over the rates, services and facilities of a person (who receives natural gas from another person within or at the boundary of a State all of which natural gas so received is ultimately consumed within such State) and is exercising such jurisdiction shall constitute conclusive evidence of such regulatory power or jurisdiction even in cases where such State commission does not have jurisdiction by reason of State law, or is not exercising jurisdiction, over the sale for resale or transportation of VNG.

(c) PERSONS WITH SERVICE AREA DETERMINATIONS.—For purposes of the Natural Gas Act—

(1) SALE FOR RESALE.—In the case of a sale for resale of VNG by the holder of a service area determination under section 7(f) of the Natural Gas Act, such sale for resale shall be subject to the exclusive jurisdiction of the State commission in the State in which physical delivery of such VNG occurs, whether or not physical combustion of such VNG occurs in another State.

(2) TRANSPORTATION.—In the case of transportation of VNG by the holder of a service area determination under section 7(f) of the Natural Gas Act, such VNG shall for purposes of section 7(f)(2) of the Natural Gas Act be deemed to be "consumed" within the State in which physical delivery of such VNG occurs, whether or not physical combustion of such VNG occurs in another State.

(3) STATE REGULATION.—In case of a sale for resale of VNG, or the transportation of VNG, by a holder of a service area determination under section 7(f) of the Natural Gas Act, such sale for resale or transportation shall be deemed to be subject to the exclusive jurisdiction of the State commission of the State in which such sale for resale or transportation occurs

whether or not the sale for resale or transportation of VNG is subject to the jurisdiction of the State commission under State law.

* * * * * * *

II

102D CONGRESS
1ST SESSION

S. 570

To implement the National Energy Strategy, and for other purposes.

IN THE SENATE OF THE UNITED STATES

MARCH 6 (legislative day, FEBRUARY 6), 1991

Mr. JOHNSTON (for himself and Mr. WALLOP) (by request) introduced the following bill; which was read twice and referred to the Committee on Energy and Natural Resources

---

A BILL

To implement the National Energy Strategy, and for other purposes.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That this Act may be cited as the "National Energy Strategy Act".

* * * * * * *

TITLE II—NATURAL GAS

Subtitle A—Natural Gas Pipeline Regulatory Reform

Gas Delivery Interconnection

SEC. 201. Section 7(a) of the Natural Gas Act (15 U.S.C. 717f(a)) is amended to read as follows—

"(a)(1) Whenever the Commission, after notice and opportunity for hearing, finds such action necessary or desirable in the public interest, it may by order direct a natural-gas company or a person who has constructed, extended, or acquired, or is operating a facility under section 7(k) of this Act to extend or improve its transportation facilities; to establish physical connection of its transportation facilities with the facilities of, and sell natural gas to, any person or municipality engaged or legally authorized to engage in the local distribution of natural or artificial gas to the public; and for such purpose to extend its transportation facilities to communities immediately adjacent to such facilities or to territory served by such natural-gas company or person, if the Commission finds that

no undue burden will be placed upon the natural-gas company or person thereby.

"(2) Upon the petition of any person, the Commission, by order, may direct a natural-gas company or a person who has constructed, extended, or acquired, or is operating a facility under section 7(k) of this Act to establish, at petitioner's expense, physical connection of its transportation facilities with the petitioner's facilities in order to receive natural gas from the petitioner's facilities.

"(3) The Commission shall have no authority to—

"(A) compel the enlargement of transportation facilities for purposes described in paragraphs (1) and (2) of this subsection, or

"(B) compel a natural-gas company or a person who has constructed, extended, acquired, or who is operating a facility under section 7(k) of this Act to establish a physical connection or sell natural gas,

when to do so would impair its ability to render adequate service to its customers.".

NEPA COMPLIANCE

SEC. 202. (a) Section 7(c) of the Natural Gas Act (15 U.S.C. 717f(c)) is amended by adding the following after paragraph (2):

"(3) For purposes of the National Environmental Policy Act of 1969 (42 U.S.C. 4321 et seq.), the authorization of construction or extension of fa-

cilities by issuance of a certificate of public convenience and necessity by the Commission is the only Federal action that is considered a major Federal action requiring a detailed statement on the environmental impact of the proposed action in connection with the construction or extension of facilities.".

(b) Notwithstanding any other law, the Commission may charge an applicant directly for environmental documentation costs the Commission incurs in processing applications filed for permission to construct and operate natural gas pipeline facilities under the Natural Gas Act (15 U.S.C. 717 et seq.) and applications filed for hydroelectric licenses and relicenses under the Federal Power Act (15 U.S.C. 791 et seq.). Such a charge shall not be applied against the Commission's annual appropriations.

AMENDMENT TO SECTION 311 OF THE NATURAL GAS POLICY ACT OF 1978

SEC. 203. Section 311 of the Natural Gas Policy Act of 1978 (15 U.S.C. 3371) is amended by—

(1) amending the catchline to read as follows:

"SEC. 311. AUTHORIZATION OF CERTAIN SALES, TRANSPORTATION, AND CONSTRUCTION."; AND

(2) in subsection (a)—

(A) amending paragraph (1)(A) to read as follows:

"(A) IN GENERAL.—The Commission shall authorize, by rule or order, any interstate pipeline to transport natural gas on behalf of—

"(i) any intrastate pipeline,

"(ii) any local distribution company, or

"(iii) any other person.";

(B) amending paragraph (2)(A) to read as follows:

"(A) IN GENERAL.—The Commission shall authorize, by rule or order, any intrastate pipeline to transport natural gas on behalf of—

"(i) any interstate pipeline,

"(ii) any local distribution company served by any interstate pipeline, or

"(iii) any other person."; and

(C) adding the following after paragraph (2):

"(3) CONSTRUCTION.—Upon thirty days notification to the affected State commission, an interstate pipeline may construct facilities for transportation service provided under this subsection. Rates, terms, and conditions for services provided through facilities constructed for transportation service au-

thorized under this subsection are not subject to State regulation.".

OPTIONAL CERTIFICATE PROCEDURES

SEC. 204. (a) Section 4 of the Natural Gas Act, (15 U.S.C. 717c) is amended—

(1) in subsection (a), by adding the following after "unlawful." "A rate or charge made, demanded or received by any natural-gas company in connection with the transportation or sale of natural gas through facilities authorized under section 7(i) of this Act is just and reasonable and complies with subsection (b) of this section if the natural-gas company and the person paying the rate or charge mutually agree to that rate or charge."; and

(2) by adding the following subsection after subsection (e)—

"(f) Subsections (c), (d), and (e) of this section do not apply to the transportation or sale of natural gas through facilities authorized by a certificate issued under section 7(i) of this Act.".

(b) Section 5(a) of the Natural Gas Act, (15 U.S.C. 717d) is amended by adding the following after the period "This subsection does not apply to any rate, charge, or classification by a natural-gas company in connection with transportation or sale of natural gas through facilities au-

thorized by a certificate issued under section 7(i) of this Act.".

(c) Section 7 of the Natural Gas Act, (15 U.S.C. 717f) is amended—

(1) in subsection (c)(1)(B), by striking the period after "interest" and inserting ": *Provided further,* That the Commission shall issue a certificate for the construction, extension, or acquisition of facilities for the transportation or sale of natural gas and for the operation of those facilities for that purpose to a natural-gas company that fulfills the terms and conditions contained in section 7(i) without requiring a hearing or further proof that the public convenience and necessity would be served by those facilities. Such a certificate shall be non-exclusive and non-prejudicial to an application for any other authorization under the Natural Gas Act or the Natural Gas Policy Act."; and

(2) by adding the following two subsections after subsection (h)—

"(i)(1) The Commission shall issue to an applicant a certificate of public convenience and necessity to undertake the construction or extension of any facilities if the following terms and conditions are attached to the issuance of the certificate and to the exercise of the rights granted under it—

"(A) The applicant shall not include any costs or expenses it incurs in relation to the operation, sale, service, construction, extension, or acquisition of facilities covered by the certificate issued under this subsection in the rates and charges of any schedule required to be filed with the Commission under section 4(c);

"(B) Notwithstanding section 15(a) of this Act, the holder of a certificate issued under this subsection shall not participate in any proceedings under this Act to consider the application for a certificate for the construction or extension of facilities that, upon completion, would serve the service area served by the facilities authorized by the holder's certificate issued under this subsection.

"(2) The Commission shall issue to any applicant a certificate of public convenience and necessity authorizing the acquisition or operation of any facilities for which a certificate for the construction or extension has been issued under this subsection or for which abandonment of facilities or services subject to the jurisdiction of the Commission, including any sales or service rendered by means of such facilities, has been approved by the Commission under subsection (b) of this section if the terms and conditions in paragraph (1) (A) and (B) are attached to the

issuance of the certificate and to the exercise of the rights granted under it.

"(j)(1) If the Commission, after a hearing held upon the petition of a person who has made a bona-fide offer to enter into a contract, finds that the failure to provide a requested rate, charge, classification, or practice in connection with the transportation of natural gas through facilities constructed, extended, acquired, or operated under a certificate issued under either section 7(i) or section 7(k) of this Act is unduly discriminatory, the Commission, considering market conditions and, to the extent relevant, the entire range of rates and services provided to others for transportation through those facilities, shall determine the rates, charges, classifications, or practices which are not unduly discriminatory to be observed and in force with respect to transportation to be provided to the petitioner, and shall fix the same by order.

"(2) A petition filed with the Commission under subsection (j)(1) shall contain a description of the transportation service sought, including the rates, charges, classifications, or practices requested by the petitioner, and the basis for asserting that the failure to provide the requested rates, charges, classifications, or practices is unduly discriminatory. Unless the Commission determines that capacity, in whole or in part, is not available to provide the

transportation service sought by the petitioner, it shall issue an order within sixty days after the filing of the petition directing the requested transportation service to commence on the terms sought. However, if within sixty days of the filing of the petition, the person against whom the petition is filed responds by filing with the Commission the rates, charges, classifications, or practices which that person considers to be not unduly discriminatory for the service sought by the petitioner, the requested service shall commence sixty days after the filing of the petition, based upon the rates, charges, classifications, or practices filed in response, except to the extent the Commission finds capacity is not available. Any rate or charge collected on the basis of the response is subject to refund, with interest, by the person providing the transportation service for that portion which is collected in excess of rates or charges requested in the petition and which the Commission finds, after hearing, to be unduly discriminatory. The burden of proof to show that any rate or charge in excess of those filed in the petition is not unduly discriminatory is upon the person filing in response to the petition.".

NONJURISDICTIONAL OPTION

SEC. 205. (a) Section 7 of the Natural Gas Act, (15 U.S.C. 717f) is amended as follows—

(1) in subsection (c)(1)(A) by striking "No" and inserting in its place "Except as provided in sec-

tion 311 of the Natural Gas Policy Act of 1978 (15 U.S.C. 3371) or subsection (j) of this section, no", and

(2) adding the following after subsection (j), as added by this subtitle—

"(k)(1) A person may elect to construct, extend, acquire, or operate a facility for the transportation or sale of natural gas and engage in the transportation or sale of natural gas through that facility without a certificate of public convenience and necessity issued by the Commission under this section.

"(2) If a person elects under this subsection not to obtain a certificate of public convenience and necessity—

"(A) the person is not a natural-gas company for the purposes of this Act in relation to the construction, extension, acquisition, or operation of facilities under this subsection or any sales or services rendered by means of such facilities;

"(B) notwithstanding section 15(a) of this Act, the person shall not participate in any proceeding under this Act to consider an application for a certificate for the construction or extension of facilities that, upon completion, would serve the service area served by the facility or extension constructed under this subsection;

"(C) the construction or extension of a facility authorized under this subsection may be subject to regulation by a State; however, rates or charges for the transportation or sale of natural gas by means of a facility or extension authorized under this subsection are not subject to regulation by a State, except that they may be regulated if that facility or extension is engaged solely in activities described in section 1(c) of this Act (15 U.S.C. 717(c))."

(b) Section 4 of the Natural Gas Act (15 U.S.C. 717c) is amended by adding after subsection (f) as added by this subtitle, the following new subsection—

"(g) After a hearing held upon the application of a natural-gas company, if the Commission finds that the natural-gas company has demonstrated that a market that the natural-gas company is authorized to serve is competitive and that the natural-gas company's transportation or sales services are offered in that market on a not unduly discriminatory basis, the Commission may issue an order finding that the rates and charges made, demanded, or received by the natural-gas company for or in connection with the transportation or sale of natural gas in that market are not subject to the jurisdiction of the Commission under this Act. A hearing held under this section is subject to section 15 of this Act.".

Subtitle B—Natural Gas Import/Export Deregulation

Coverage of Natural Gas Act

SEC. 211. Section 1(c) of the Natural Gas Act (15 U.S.C. 717(c)) is amended by inserting "or exported from such State" after "State" the second time it appears.

DEFINITIONS

SEC. 212. Section 2 of the Natural Gas Act (15 U.S.C. 717a) is amended—

(1) in paragraph (7) by inserting "including a foreign country," after "thereof," both places it appears, and

(2) by adding the following after paragraph (9):

"(10) 'Importation' means the actions involved in bringing natural gas into the United States.

"(11) 'Exportation' means the actions involved in taking natural gas out of the United States.".

NATURAL GAS IMPORTS AND EXPORTS

SEC. 213. Section 3 of the Natural Gas Act (15 U.S.C. 717b) is amended to read as follows:

"EXPORTATION OR IMPORTATION OF NATURAL GAS

"SEC. 3. (a) Importation of natural gas is considered a first sale for purposes of this Act and the Natural Gas Policy Act of 1978 (15 U.S.C. 3301–3432).

"(b) Neither the Commission nor a State may prohibit or condition the exportation or importation of natural gas or treat exported or imported natural gas while

it is within the United States differently than any other natural gas.

"(c) The President may prohibit or condition the exportation or importation of natural gas upon finding that it is in the national interest.

"(d) Upon finding that the exportation or importation of natural gas is in the national interest, the President may waive any law relating to the exportation or importation of natural gas or may specify, by schedule or otherwise, when a particular law relating to the exportation or importation of natural gas is considered satisfied if the appropriate Federal or State agency has not taken final action.".

Subtitle C—Structural Reform of the Federal Energy Regulatory Commission

NATURAL GAS AND ELECTRICITY ADMINISTRATION

SEC. 221. (a) Section 2(a) of the Department of Energy Organization Act (42 U.S.C. 7101(a)) is amended by striking ", including the Federal Energy Regulatory Commission".

(b) Section 204 of the Department of Energy Organization Act (42 U.S.C. 7134) is amended to read as follows:

"NATURAL GAS AND ELECTRICITY ADMINISTRATION

"SEC. 204. There shall be within the Department a Natural Gas and Electricity Administration established by

title IV of this Act to be headed by an Administrator who shall be appointed by the President, by and with the advice and consent of the Senate, and who shall be compensated at the rate provided for in level III of the Executive Schedule under section 5314 of title 5, United States Code.".

(c) Section 301(b) of the Department of Energy Organization Act (42 U.S.C. 7151(b)) is amended to read as follows:

"(b) There are transferred to, and vested in, the Secretary the functions of the Federal Power Commission, the Federal Energy Regulatory Commission, and the members, officers, or components thereof.".

(d) Section 306 of the Department of Energy Organization Act (42 U.S.C. 7155) is amended by striking "Except as provided in title IV, there" and inserting in its place "There".

(e) Title IV of the Department of Energy Organization Act is amended to read as follows:

"TITLE IV—NATURAL GAS AND ELECTRICITY ADMINISTRATION APPOINTMENT AND ADMINISTRATION

"SEC. 401. (a) There is established within the Department an Administration to be known as the Natural Gas and Electricity Administration.

"(b) The Secretary is responsible for the executive and administrative operation of the Natural Gas and Electricity Administration, including functions of the Natural Gas and Electricity Administration with respect to the appointment and employment of hearing examiners in accordance with title 5, United States Code.

"(c) The Secretary may require that hearing examiners appointed under this section conduct hearings on any matter within the Secretary's jurisdiction.

RULEMAKING PROCEEDINGS FOR RATES AND CHARGES

"SEC. 402. (a) Any function transferred to the Secretary under section 301(b) or section 306 of this Act which relates to the establishment of rates and charges under the Federal Power Act or the Natural Gas Act may be conducted by rulemaking procedures. Except as provided in subsection (b), the procedures in such a rulemaking proceeding shall assure full consideration of the issues and an opportunity for interested persons to present their views.

"(b) With respect to any rule or regulation promulgated by the Secretary to establish rates and charges for the first sale of natural gas by a producer or gatherer to a natural gas pipeline under the Natural Gas Act, the Secretary may afford any interested person a reasonable opportunity to submit written questions with respect to disputed issues of fact to other interested persons participat-

ing in the rulemaking proceedings. The Secretary may establish a reasonable time for both the submission of questions and responses.".

(f) Section 501(a) of the Department of Energy Organization Act (42 U.S.C. 7191(a)) is amended—

(1) by striking "(1)";

(2) by striking "other than the Commission,"; and

(3) by striking paragraph (2).

(g) Section 502 of the Department of Energy Organization Act (42 U.S.C. 7192) is amended:

(1) in subsection (a) by striking ", the Commission"; and

(2) in subsection (c) by striking "Subject to the provisions of section 401 of this Act, and notwithstanding" and inserting in its place "Notwithstanding".

(h) Section 503 of the Department of Energy Organization Act (42 U.S.C. 7193) is amended—

(1) by amending subsection (c) to read as follows:

"(c) If within thirty days after the receipt of the remedial order issued by the Secretary, the person notifies the Secretary that he intends to contest a remedial order issued under subsection (a) of this section, the Secretary

shall stay the effect of the remedial order, unless the Secretary finds the public interest requires immediate compliance with the order. The Secretary, upon request, shall afford an opportunity for a hearing, including, at a minimum, the submission of briefs, oral or documentary evidence, and oral arguments. To the extent that the Secretary determines that the right of cross examination is required for a full and true disclosure of the facts, the Secretary shall afford it. The Secretary shall thereafter issue an order, based on findings of fact, affirming, modifying, or vacating the remedial order, or directing other appropriate relief, and such order shall, for the purpose of judicial review, constitute a final agency action."; and

(2) by striking subsection (d).

(i) Section 504 of the Department of Energy Organization Act (42 U.S.C. 7194) is amended—

(1) in subsection (b)(1) by striking "Commission" and inserting in its place "Secretary"; and

(2) in subsection (b)(2) to read as follows:

"(b)(2) The Secretary shall, by rule, establish appropriate procedures, including a hearing when requested, for review of a denial. Action by the Secretary under this section shall be considered final agency action within the meaning of section 704 of title 5, United States Code.".

(j) Section 605(a)(3) of the Department of Energy Organization Act (42 U.S.C. 7215(a)(3)) by striking "or the Commission, as the case may be,".

(k) Section 649(a) of the Department of Energy Organization Act (42 U.S.C. 7259(a)) is amended by striking "and the Federal Energy Regulatory Commission" and "or the Commission".

(l)(1) Section 705 of the Department of Energy Organization Act (42 U.S.C. 7295) is amended—

(A) in subsection (a)(1) by striking "or the Commission"; and

(B) in subsection (a)(2) by striking "the Federal Energy Regulatory Commission,"; and

(C) in subsection (b)(2) by striking "and the Commission" and "or the Commission".

(2) For purposes of the transfer of functions from the Federal Energy Regulatory Commission to the Secretary of Energy by this Act, the phrases "the time this Act takes effect", "the date this Act takes effect", and "the date on which this Act takes effect" in section 705 of the Department of Energy Organization Act (42 U.S.C. 7295) are considered to refer to the date of enactment of this Act.

(m) Section 707 of the Department of Energy Organization Act (42 U.S.C. 7297) is amended by striking "the Federal Energy Regulatory Commission,".

(n) Section 708 of the Department of Energy Organization Act (42 U.S.C. 7298) is amended by striking "Except as provided in title IV, nothing" and inserting in its place "Nothing".

(o) Title 5, United States Code, is amended—

(1) in section 5314 by striking the following item: "Chairman, Federal Energy Regulatory Commission." and inserting in its place "Administrator, Natural Gas and Electricity Administration"; and

(2) in section 5315 by striking the following item: "Members, Federal Energy Regulatory Commission.".

(p) Section 901 of the Department of Energy Organization Act (42 U.S.C. 7341) is amended by striking "and the Commission" and "or the Commission".

(q) The Table of Contents of the Department of Energy Organization Act is amended—

(1) by striking the item for section 204 and inserting in its place "Natural Gas and Electricity Administration."; and

(2) by amending the items relating to title IV to read as follows:

"TITLE IV—NATURAL GAS AND ELECTRICITY ADMINISTRATION

"Sec. 401. Appointment and administration.
"Sec. 402. Rulemaking proceedings for rates and charges.".

* * * * * * *

II

102D CONGRESS
1ST SESSION

S. 662

To increase the use of natural gas in the United States.

IN THE SENATE OF THE UNITED STATES

MARCH 14 (legislative day, FEBRUARY 6), 1991

Mr. WIRTH introduced the following bill; which was read twice and referred to the Committee on Energy and Natural Resources

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A BILL

To increase the use of natural gas in the United States.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

FINDING AND PURPOSES

SEC. 1001. FINDINGS.—The Congress finds that—

(1) adoption of a sound energy policy is essential to the protection of our nation's economic health, our national security, and to the welfare of our citizens;

(2) such a policy must employ diverse sources of energy, particularly those sources that are both domestically available and environmentally sound;

(3) exploration and production of existing sources of energy must be enhanced at the same time as extensive research into alternative sources of energy is being conducted and efforts to conserve energy are being promoted; and

(4) the usage of natural gas should be enhanced, and yet the regulatory and statutory structure for the natural gas industry has imposed burdens which have resulted in a decline of natural gas consumption, which is contrary to the national interest.

SEC. 1002. PURPOSES.—The purposes of this Act are to—

(1) reduce our reliance on foreign supplies of energy to the point where the United States is energy independent by the year 2025;

(2) encourage the development of domestically available oil and gas while reducing the amount of energy used by promoting conservation;

(3) enhance competition in the natural gas industry by removing or revising burdensome regulatory and statutory provisions which create disincentives to competition;

(4) enhance the usage of natural gas through improving access to new markets, fostering demand

in the marketplace, and correcting the lack of financial incentives to pursue high-risk gas transportation projects;

(5) foster and promote the development of alternative sources of energy, including renewable resources; and

(6) encourage the development and utilization of environmentally sound sources of energy, such as compressed natural gas for vehicular use and solar energy for residential and commercial use.

DEFINITIONS

SEC. 1003. DEFINITIONS.—As used in this Act, the term—

(a) "Commission" means the Federal Energy Regulation Commission, or any successor agency, unless otherwise provided;

(b) "cost-based rates"—Rates for services that remain subject to Commission review based upon a traditional cost-of-service determination;

(c) "Department" means the Department of Energy, unless otherwise provided;

(d) "just and reasonable"—shall be defined by these amendments notwithstanding any conflict between these amendments and Commission or court precedent;

(e) "Merchant Service" means the purchase and sale for resale of natural gas in interstate commerce;

(f) "Secretary" means the Secretary of Energy, unless otherwise provided;

(g) "used and useful" means a determination by the Commission as defined by Commission and court precedent that plant is used and useful; and

(h) "workable competition" means a finding by the Commission that sufficient competition exists to allow rates and other terms and conditions of service to be established by market conditions.

SEC. 1004. VEHICULAR NATURAL GAS JURISDICTION.—(a) DEFINITIONS.—For the purposes of this section—

(1) the term "VNG" means natural gas for ultimate use as a fuel in a motor vehicle, and includes compressed natural gas; and

(2) the term "Motor Vehicle" includes any automobile, truck, bus, van, or other on-road or off-road motor vehicle, including a boat.

(b) PERSONS WITH HINSHAW EXEMPTIONS.—

(1) PLACE OF ULTIMATE CONSUMPTION.—For purposes of section (1)(c) of the Natural Gas Act, in the case of any sale of VNG, such VNG shall be

deemed to be "ultimately consumed" within the State in which physical delivery of such VNG occurs, whether or not physical combustion of such VNG occurs in another State.

(2) STATE REGULATION.—For purposes of section (1)(c) of the Natural Gas Act, certification from a State commission to the Federal Regulatory Commission that such State commission has regulatory jurisdiction over the rates, services and facilities of a person (who receives natural gas from another person within or at the boundary of a State all of which natural gas so received is ultimately consumed within such State) and is exercising such jurisdiction shall constitute conclusive evidence of such regulatory power or jurisdiction even in cases where such State commission does not have jurisdiction by reason of State law, or is not exercising jurisdiction, over the sale for resale or transportation of VNG.

(c) PERSONS WITH SERVICE AREA DETERMINATIONS.—For purposes of the Natural Gas Act—

(1) SALE FOR RESALE.—In the case of a sale for resale of VNG by the holder of a service area determination under section 7(f) of the Natural Gas Act, such sale for resale shall be subject to the exclusive jurisdiction of the State commission in the

State in which physical delivery of such VNG occurs, whether or not physical combustion of such VNG occurs in another State.

(2) TRANSPORTION.—In the case of transportation of VNG by the holder of a service area determination under section 7(f) of the Natural Gas Act, such VNG shall for purposes of section 7(f)(2) of the Natural Gas Act be deemed to be consumed within the State in which physical delivery of such VNG occurs, whether or not physical combustion of such VNG occurs in another State.

(3) STATE REGULATION.—In case of a sale for resale of VNG, or the transporation of VNG, by a holder of a service area determination under section 7(f) of the Natural Gas Act, such sale for resale or transportation shall be deemed to be subject to the exclusive jurisdiction of the State commission of the State in which such sale for resale or transportation occurs whether or not the sale for resale or transportation of VNG is subject to the jurisdiction of the State commission under State law.

SEC. 1005. FEDERAL PROGRAMS TO PROMOTE VEHICULAR NATURAL GAS.—With six months following enactment of this Act, the Secretary shall—

(a) institute a government-sponsored awareness program for alternative fuels designed to educate potential purchasers of the costs of such fuels as well as their emission characteristics and other features;

(b) identify and report to Congress on purchasing policies of the Federal Government which inhibit or prevent the purchase by the Federal Government of alternative-fueled vehicles;

(c) report to Congress on Federal, State, and local traffic control measures and policies and how the use of alternative-fueled vehicles could be promoted by granting such vehicles exemptions or preferential treatment under such measures; and

(d) develop a plan for the establishment of a trust fund for loans to convert vehicles to operate on alternative fuels or to purchase vehicles which operate on alternative fuels, with such loans to be repaid by the borrower from the cost differential between gasoline and the alternative fuel on which the vehicle operates.

SEC. 1006. FEDERAL PERMITTING REQUIREMENTS.—Facilities which are constructed or used solely for the sale of vehicular natural gas to the public for use as fuel in a motor vehicle shall not be considered a major

source as that term is defined in the Clean Air Act Amendments of 1990.

SEC. 1007. MASS TRANSIT PROGRAM.—(a)(1) The Secretary, consistent with the provisions of this Act, in consultation with the Administrator of the Urban Mass Transit Administration, may, consistent with the Alternative Motor Fuels Act of 1988 (Public Law 100–494), enter into cooperative agreements and joint ventures proposed by any municipal, county, or regional transmit authority in an urban area with a population over 100,000 (according to latest available census information) to demonstrate the feasibility, including safety of specific vehicle design, of using natural gas or other alternative fuels for mass transit.

(2) The cooperative agreements and joint ventures under paragraph (1) may include interested or affected private firms willing to provide assistance in cash, or in kind, for any such demonstration.

(b)(1) The Secretary may not enter into any cooperative agreement or joint venture under subsection (a) with any municipal, county or regional transit authority unless such government body agrees to provide at least 25 percent of the costs of such demonstration.

(2) The Secretary, at his discretion, may grant such priority under this section to any entity that demonstrates

that the use of natural gas or other alternative fuels used for transportation would have a significant effect on ability of an air quality region to comply with applicable regulations governing ambient air quality.

(c) There is authorized to be appropriated not more than $30,000,000 for each of fiscal years 1992, 1993, and 1994 for purposes of this section.

SEC. 1008. NATURAL GAS AND OTHER ALTERNATIVE FUEL USE IN FLEET VEHICLE.—(a) The Secretary, consistent with the Alternative Motor Fuels Act of 1988 (Public Law 100–494), and in consultation with the Administrator of the United States Environmental Protection Agency and the Secretary of Transportation, shall establish and carry out a program, and provide financial assistance to encourage the development and commercialization of natural gas and other alternative fuels for use in passenger fleets, light-duty trucks, and heavy-duty trucks consistent with the purposes of the Act. Such assistance shall provide for the purchase and construction of vehicles dedicated to the use of natural gas or other alternative fuels and of vehicles dually fueled by natural gas or other alternative fuels and gasoline or diesel, and associated refueling equipment.

(b) Public and private fleets may be eligible for financial assistance under this section.

(c) The Secretary, at his discretion, may grant such priority to those fleets where the use of natural gas and other alternative transportation fuels would have a significant effect on the ability of an air quality region to comply with applicable regulations governing ambient air quality.

(d) To facilitate the use of natural gas and other alternative fueled vehicles, the conversion of a vehicle from either gasoline or diesel alone to natural gas or other alternative fuels alone, or to natural gas or other alternative fuels and either gasoline or diesel, shall not be considered a violation of any antitampering provisions of the Federal law and implementing regulations: *Provided, however,* That the conversion complies with emissions standards issued by the Administrator of the Environmental Protection Agency.

(e) Any program established under this section that applies to existing vehicles shall take into consideration the safety of specific vehicle design and the compatibility of natural gas or other alternative fuel use with the original components of such existing vehicles.

(f) There is authorized to be appropriated not more than $30,000,000 for each of fiscal years 1992, 1993, and 1994, for purposes of this section.

SEC. 1009. TRAINING PROGRAM.—(a) The Secretary of Labor shall establish and carry out a training and cer-

tification program for technicians who are responsible for vehicle installation of equipment that converts gasoline or diesel-fueled vehicles to the capability to run on natural gas or other alternative fuels alone, or on natural gas or other alternative fuels and either diesel fuel or gasoline, and for the maintenance of such converted vehicles. Such training and certification programs shall provide these technicians with instruction on the correct installation procedures and techniques, adherence to specifications, vehicles operating procedures, emissions testing, and other appropriate mechanical concerns applicable to these vehicle conversions.

(b) The Secretary of Labor may enter into cooperative agreements with, and provide financial assistance to, under this section, appropriate parties to provide training programs that will ensure the proper operation and performance of conversion equipment.

(c) The program under this section shall be consistent with the Alternative Motor Fuels Act of 1988 (Public Law 100–494).

(d) There is authorized to be appropriated not more than $5,000,000 for each of the fiscal years 1992, 1993, and 1994 for purposes of this section.

SEC. 1010. VEHICLE RESEARCH, DEVELOPMENT, AND DEMONSTRATION PROGRAM.—(a) The Secretary

shall carry out a program of research, development, and demonstration on techniques related to improving natural gas and other alternative fueled vehicle technology including, but not limited to, the following areas—

(1) fuel injection;

(2) carburetion;

(3) manifolding;

(4) combustion;

(5) power optimization;

(6) efficiency;

(7) lubricants and detergents;

(8) engine durability;

(9) ignition, including fuel additives to assist ignition;

(10) multifuel engines;

(11) emissions control, including catalysts;

(12) novel gas compression concepts;

(13) advanced storage systems;

(14) advanced gaseous fueling technologies; and

(15) the incorporation of advanced materials in these areas.

(b) The Secretary, consistent with the Alternative Motor Fuels Act of 1988 (Public Law 100–494), may enter into cooperative agreements with, and provide financial assistance to, under this section, public entities or in-

terested or affected private firms willing to provide 50 percent of the costs of such programs to perform the research and development necessary to improve natural gas vehicle and other alternative fuel vehicle technology.

(c) There is authorized to be appropriated not more than $10,000,000 for each of the fiscal years 1992, 1993, and 1994 for purposes of this section.

SEC. 1011. NATURAL GAS COFIRING RESEARCH, DEVELOPMENT AND DEMONSTRATION.—(a) DEFINITIONS.—For the purposes of this section, the term—

(1) "cofiring" means the injection of natural gas and pulverized coal into the primary combustion zone of an electric utility unit or an industrial boiler and shall include gas reburn technologies; and

(2) "gas reburn" means the injection of natural gas into the upper furnace region of an electric utility unit or an industrial boiler to produce a fuel-rich zone thereby reducing nitrogen oxide emissions.

(b) The Secretary shall conduct a program of research, development and demonstration of cofiring in electric utility units and large industrial boilers in order to determine optimal natural gas injection levels for both environmental and operational benefits.

(c) The Secretary may provide financial assistance under this section to public entities or interested or af-

fected private firms to perform the research, development and demonstration of cofiring technologies.

(d) The Secretary may enter into cooperative agreements with, and provide financial assistance under this section to, public entities or interested or affected private firms willing to provide at least 50 percent of the costs of such programs to perform the research, development and demonstration of cofiring technologies.

(e) For purposes of this section, there is authorized to be appropriated to the Secretary not more than $9,000,000 for each of the fiscal years 1992, 1993, and 1994.

SEC. 1012. NATURAL GAS RECOVERY, RESEARCH, DEVELOPMENT AND DEMONSTRATION PROGRAM.—(a) The Secretary shall expand and continue a program of research, development, and demonstration on techniques to increase the availability of natural gas from—

(1) intensive recovery of natural gas in place in discovered reservoirs or formations; and

(2) economic recovery of nonconventional sources of natural gas, including gas from tight formations, Devonian shales, gas from less permeable formations coalseams, and geopressured brines.

(b) The Secretary shall seek to enter into joint ventures with persons engaged in the production, transpor-

tation, distribution, or major use of natural gas to implement the program under subsection (a).

(c) There is authorized to be appropriated not more than $25,000,000 for each of the fiscal years 1992, 1993, and 1994 for purposes of this section.

SEC. 1013. NATURAL GAS AND ELECTRIC HEATING AND COOLING TECHNOLOGIES.—(a) The Secretary shall expand the program for research, development, and demonstration for natural gas and electric heating and cooling technologies for residential and commercial buildings.

(b) The natural gas heating and cooling program shall increase research on thermally activated heat pumps including:

(1) absorption heat pumps; and

(2) engine-driven heat pumps.

(c) The electric heating and cooling program shall increase research on:

(1) advanced heat pumps;

(2) thermal storage; and

(3) advanced electrically-driven HVAC (heating, ventilation, and cooling) and refrigeration systems that utilize replacements for chlorofluorocarbons, including HCFC–22.

(d) There is authorized to be appropriated to the Secretary, not more than $15,000,000 for each of the fiscal

years 1992, 1993, and 1994 for purposes of this section in addition to current authorizations.

SEC. 1014. APPLICABILITY OF NEW SOURCE REVIEW TO EXISTING ELECTRIC UTILITY STEAM GENERATING UNITS.—(a) POLLUTION CONTROL PROJECTS.—For purposes of the Clean Air Act, no physical change in, or change in the method of operation of, an electric utility steam generating unit which is undertaken for purposes of pollution control, including the use of natural gas and clean coal technologies, shall be treated as a modification for a specific regulated pollutant for purposes of part C or D of title I of the Clean Air Act if such change does not increase the potential emissions of the specific regulated pollutant from such source above the potential emissions before the change.

(b) NITROGEN OXIDE CONTROL REQUIREMENTS.—

(1) For purposes of the Clear Air Act, any modification, as defined in section 169(c)(2) of such Act, at an existing electric utility steam generating unit subject to section 165 of the Clean Air Act shall be deemed to satisfy the technology requirements of section 165(a)(4) thereof for nitrogen oxides if it meets the following conditions:

(A) For a unit subject to a requirement promulgated pursuant to section 407 of the

Clean Air Act, immediately following the modification, the unit shall be required to meet nitrogen oxide emissions limitations specified for that boiler type pursuant to section 407. In the event that the modification precedes the establishment of nitrogen oxide emissions limitations for that boiler type pursuant to section 407, the unit shall be required to meet the applicable emission limitation upon the date required by the regulation.

(B) For an existing electric utility steam generating unit not subject to section 407 of the Clean Air Act immediately following the modification, the unit shall be required to meet the nitrogen oxide limit equivalent to the limit achievable using "low-NO_x burners".

(2) Any State or local permitting authority shall retain the right to impose more stringent limitations for control of nitrogen oxides.

SEC. 1015. NO_x REQUIREMENTS FOR NATURAL GAS FACILITIES.—The Clean Air Act, as amended is further amended by inserting the following new subparagraph following section 182(f)(B):

"(C) major stationary sources which use natural gas as its primary fuel.".

REGULATORY ISSUES

SEC. 1016. INCENTIVE RATEMAKING OPTIONS.—(a) Section 4(a) of the Natural Gas Act (15 U.S.C. 717c(a)) is amended by adding: "Rates shall be designed to efficiently allocate capacity, maximize throughput, eliminate cross-subsidies among customer classes and between merchant and transportation services, reflect any material distance-related variation in the cost of providing service, and appropriately unbundle distinct services. Such rates shall be deemed just and reasonable if (1) they are designed to provide a reasonable opportunity to recover prudently incurred costs and to earn a fair rate of return on the natural gas company's investment, or (2) they are determined pursuant to an incentive formula approved by final and nonappealable Commission order, the original term of effectiveness of which formula has not expired at the time of rate review, or (3) they fall within a Commission-prescribed zone of reasonableness, the upper limit of which shall be the rates yielded by incorporating a current market valuation of the natural gas company's investment and lower limit of which shall provide for the minimum return on investment necessary to attract and retain capital. The Commission is directed to develop an incentive formula as used in subparagraph (2) herein, with the goals of allowing natural gas companies to earn a fair rate of return,

providing proper price signals to the marketplace, and rewarding pipeline efficiency.".

(b) Section 5(a) of the Natural Gas Act (15 U.S.C. 717d(a)) is amended by deleting "or are not the lowest reasonable rates" and adding: "exceed the rates established by formula pursuant to section 717c(a)(2) of title 15, United States Code, or, in the absence of such formula, exceed the upper limit of the zone of reasonableness prescribed at section 717c(a)(3) of title 15, United States Code.".

SEC. 1017. REHEARING TIME LIMITS.—Section 19(a) of the Natural Gas Act (15 U.S.C. 717r(a)) is amended by striking the fourth sentence and inserting in lieu thereof the following: The Commission shall take final action on the merits of the application for rehearing within 60 days after such application is filed, and the Commission may not defer action on the merits of the application through issuance of an order during that 60 day period. Unless the Commission takes final action on the merits of such application within 60 days after it is filed, the application for rehearing shall be deemed to have been denied.

SEC. 1018. FILING OF JOINT RATES.—Section 4 of the Natural Gas Act (15 U.S.C. 717c) is amended by adding the following new section 4(f): "Under such rules and

regulations as the Commission may prescribe, natural gas companies subject to the Commission's jurisdiction under this Act, may file with the Commission for its approval, joint rates which have been negotiated by them for the transportation of natural gas through each of their pipelines in sequence on the way to market. Neither the provisions of sections 1 and 2 of the Sherman Antitrust Act, in sections 1 and 2 of title 15, United States Code, nor any other antitrust law, whether federal or state, shall preclude the development or utilization of such joint rates."

SEC. 1019. FAIR RETURN ON INVESTMENT.—Section 4(a) of the Natural Gas Act (15 U.S.C. 717c(a)) is amended by adding: "Notwithstanding the specific methodology used to set the rates of the natural gas company, to the extent that the dollar value or cost of the natural gas company's investment in utility plants is a determinant of the allowed rate level, all such plants shall be recognized so long as it is used and useful in discharging the utility business of the natural gas company.".

SEC. 1020. COMPETITIVE SALES SERVICES.—Title VI of the Natural Gas Policy Act (15 U.S.C. 3431) is amended by adding new section 3431(b)(1)(F) of title 15, United States Code, as follows:

"SEC. . SALES FOR RESALE BY INTERSTATE PIPELINES.—For purposes of sections 4 and 5 of the Natural

Gas Act, any amount charged for a sale for resale by an interstate pipeline shall be deemed just and reasonable if—

"(i) such amount is charged pursuant to rates approved by the Commission, or

"(ii) the Commission has made and not revoked a finding that workably competitive alternatives exist for such sale for resale, subject to such rules and standards for determining such workable competition as the Commission may prescribe, including but not limited to adequate comparability between the sales services and the transportation services of the seller. If such charges are deemed just and reasonable pursuant to this paragraph, profits and losses occasioned by such sale for resale shall not be taken into consideration in any way in setting the seller's rates for other services, and the rates for such sale for resale are exempt from the tariff posting authority of the Commission pursuant to section 717c(c) of title 15, United States Code.".

SEC. 1021. COMPETITIVE SERVICES.—(a) Services provided by facilities constructed under section 311 of the Natural Gas Policy Act shall not require a certificate of public convenience and necessity.

(b) Any new service proposed and implemented by a natural gas company which does not require the construction of major new facilities shall be authorized by the acceptance of tariff sheets and shall not require a certificate of public convenience and necessity.

(c) Any new service offered by a natural gas company which can be fully supplanted with other pre-existing services subject to tariff and rate review under sections 4 and 5 of the Natural Gas Act shall be exempt from the tariff and rate review provisions of sections 4 and 5 of the Natural Gas Act.

(d) Notwithstanding the above, the Commission may consider the impact of any new services offered under this subsection in subsequent rate cases, in setting rates for other services.

SEC. 1022. PIPELINE ABANDONMENTS.—Section 7(b) of the Natural Gas Act (U.S.C. 717f(b)) is amended by adding the following at the end of the section: "A natural gas company may abandon jurisdictional sales services to customers upon the expiration of underlying sales contracts with such customers, without approval by the Commission. If a customer of a natural gas company has previously converted all or a portion of jurisdictional sales service provided by a natural gas company to jurisdictional transportation service, and such customer pays the just

and reasonable non-discriminatory rate established by the natural gas company for such service, then such transportation service shall not be abandoned by the natural gas company without approval of the Commission as provided in this section.".

WELLHEAD PRICES

SEC. 1023. PRODUCER DEMAND CHARGES.—Title VI of the Natural Gas Policy Act (15 U.S.C. 3431) is amended by adding new section 3431(c)(3) of title 15, United States Code.

"SEC. . RECOVERY OF DEMAND CHARGES.—Any fixed charge paid by an interstate pipeline to a first seller for gas supply security shall be recoverable on an 'as-billed basis' in the interstate pipeline's demand charges, unless the Commission determines, after a hearing, that the interstate pipeline does not offer a reasonably competitive alternative to its sales service.".

SEC. 1024. REGULATION OF NATURAL GAS IMPORTS.—Section 3 of the Natural Gas Act (15 U.S.C. 717(b)) is amended by adding at the end of the section the following language: "The Secretary shall condition the approval of any import application pursuant to this section upon action by the Commission to redress any anti-competitive impacts on United States gas producers, including, but not limited to, competitive disparities result-

ing from different rate designs applied to the transportation of domestic gas and imported supplies.".

ACCELERATED PIPELINE CONSTRUCTION

SEC. 1025. AUTOMATIC PIPELINE CONSTRUCTION.—Section 311 of the Natural Gas Policy Act of 1978 (15 U.S.C. 3371) is amended to add the following:

"(d)(1) The provisions of the Natural Gas Act and the jurisdiction of the Commission, except as specifically provided herein, shall not apply to the construction or operation of any facilities constructed by a natural gas company subject to the Commission's jurisdiction under the Natural Gas Act by virtue of such construction or operation, if the natural gas company constructing such facilities—

"(a) holds a certificate of public convenience and necessity issued by the Commission pursuant to section 7 of the Natural Gas Act and pursuant to which the natural gas company has agreed to provide open access transportation service; and

"(b) the natural gas company agrees that the provisions of such certificate shall apply to transportation service provided through facilities constructed under this section.

"(d)(2) All facilities constructed under this section shall be constructed in accordance with applicable laws and regulations governing environmental and safety fac-

tors: *Provided, however,* That in section 437, and the following, of title 42, United States Code, the provisions of the National Environmental Policy Act of 1978, shall not apply to the construction or operation of facilities provided for in this section.

"(d)(3) Nothing in this section shall preclude a natural gas company from filing for and/or preclude the Commission from issuing a certificate of public convenience and necessity pursuant to section 7 of the Natural Gas Act for the operation of the facilities constructed under this section.".

SEC. 1026. REBUTTABLE RESUMPTION OF NO SIGNIFICANT IMPACT.—For purposes of required environmental review of natural gas pipeline projects at the Commission, there shall be a rebuttable presumption of a finding of no significant impact ("FONSI") for any natural gas pipeline construction project which either utilizes existing utility or highway corridors, or does not involve construction in high value wetland areas.

SEC. 1027. LEAD AGENCY.—In cases where Federal Energy Regulatory Commission authorization of the construction or operation of facilities or projects under the Natural Gas Act may be deemed a major Federal action under the National Environmental Policy Act ("NEPA"), or requires the preparation of other environmental docu-

ments, the Commission shall be the lead agency and shall have primary authority for compliance with NEPA. The Commission may set reasonable time limits for consultation with other Federal agencies which participate in the review of a proposed facility or project pursuant to NEPA to complete their review of any potential environmental impacts of the construction or operation of such facility or project, and for such other agencies to consult and submit comments to the Commission.

SEC. 1028. TWO-PHASE CERTIFICATION PROCESS.—Section 7(e) of the Natural Gas Act (15 U.S.C. 717f(e)) shall be amended to add the following language at the end of the section: "The Commission shall have the power to issue certificates of public convenience and necessity in a two-phase process. The first phase certificate shall involve all matters requiring Commission review and approval other than environmental matters, and shall constitute a final order on such matters. The second phase certificate shall address only required environmental matters, and approvals and shall constitute a final order on such matters.".

SEC. 1029. PIPELINE SUBMISSION OF ENVIRONMENTAL ASSESSMENTS.—Environmental Assessments ("EA") submitted by pipelines at the time of filing for approval of proposed facilities, which EAs utilize a speci-

fied format to be determined by the Commission, will be presumptively valid, subject to initial Commission review for completeness. Nothing in this subsection shall affect the Commission's responsibility to comply with the National Environmental Policy Act of 1969.

SEC. 1030. Section 16 of the Natural Gas Act (15 U.S.C. 7170) is amended—

(1) by inserting "(a)" after "SEC. 16."; and

(2) by adding at the end of the existing section the following new subsection:

"(b) Where the Commission by rule or order requires the preparation of an environmental assessment of an environmental impact statement in connection with an application for authority to construct or extend facilities for the transportation of natural gas under this Act, the Commission shall permit the applicant to elect a contractor, consultant, or other person designated by the Commission for such purpose to prepare the environmental impact statement at the applicant's expense. The Commission shall establish procedures to ensure that the contractor, consultant, or other person has no financial or other potential conflict of interest in the outcome of the proceeding. Nothing in this subsection shall affect the Commission's responsibility to comply with the National Environmental Policy Act of 1969.".

STUDIES

SEC. 1031. GLOBAL PRODUCTION TRENDS.—The Office of Technology Assessment, in conjunction with the department, shall study and report to Congress on the global trends of production, usage, and transportation of natural gas and the ways in which these trends can affect domestic energy policy and the United States natural gas industry.

SEC. 1032. REMOVAL OF STATE AND LOCAL BARRIERS.—The Office of Technology Assessment, in conjunction with the Department, shall identify, study and report to Congress on State and locally imposed institutional and regulatory barriers to increased national natural gas usage, and make recommendations as to the establishment of a uniform national policy to enhance the use of natural gas.

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Senator WIRTH. We will proceed. Our opening witness is our very distinguished and capable governor, Roy Romer, who has had the economics of the State of Colorado first and foremost on his agenda for all of his fine tenure in office.

Governor Romer, we are delighted to have you with us. Thank you very much for being here.

STATEMENT OF HON. ROY ROMER, GOVERNOR, STATE OF COLORADO

Governor ROMER. Thank you. I am pleased to be here, and I am fascinated by the setting and the surroundings. Senator, you look at home in this cavernous hall, but I also notice that there is a fan at every one of the stations of the city council and the mayor, and I do not know what the symbolism of that is, whether or not it is a decision that it is to cool off the hot tempers or whether it is the mixture of air that needs to be, you know, the cool and the hot. I just think there is a great symbolism there, and I will figure it out before this hearing's over.

Senator WIRTH. Methane and global warming.

Governor ROMER. All right. I appreciate the invitation to be here and I am pleased to see so many advocates of the natural gas industry here today. As a regional center for this industry, we are pleased to showcase our partnership with Colorado's oil and gas industry.

Natural gas is a strategic link to this nation's energy security. It is clean, abundant and adaptable to a variety of uses. Expanded use can reduce our dependence on foreign oil.

In 1989, I outlined an eight-point plan to expand the market for our oil and gas resources. These initiatives are designed to encourage economically efficient and environmentally responsible industries. In these efforts, we are asking all affected parties—producers, transporters, the Federal Government, State and local governments and consumers—to assist in making these industries more competitive, and I am pleased to say that partnership is working.

Last June, we unveiled the nation's first natural gas vehicle company and the first compressed natural gas fueling station in the region. We are signing new customers for Colorado gas on the West Coast. We have completed some important new linkages in our pipeline network. The natural gas production reached record production levels in 1990. And last fall we opened the first vehicle conversion facility.

The oil and gas industry represents a significant component of Colorado's economy, providing jobs for our citizens and revenues to State and local government. The oil and gas industry payroll in Colorado, valued at $580 million, employs over 14,000 people in extraction and over 4,800 people in processing, transmitting—transmission, and refining. In total, the industry and related businesses support over 100,000 jobs and a $1.2 billion payroll.

Let me speak about Colorado's oil and gas plan. At the State level, we are integrating the environmental regulation of the energy industry with the promotion of our vast resources so that operations are both economically healthy and environmentally sound. We have advocated State primacy in national environmen-

tal regulations to avoid duplication and preemption of State and local laws. And we have promoted reform in the way Federal royalties are set, Federal lands are leased and public lands are managed. I firmly believed that we can protect the environment and public health, while not overregulating the industry.

Now, let me update you on recent actions relating to our eight-point oil and gas plan. First, transportation and rates. The existing pipeline system has made Colorado a net importer of gas rather than a net exporter. We have begun working with the industry on proposals for new lines and extensions. Underlying our support for these proposals is the principle that they may be—that they must be cost-efficient and environmentally responsible.

Related to the pipeline system is the rate charged by pipeline owners. We support a rate structure based on distance and cost, rather than on a flat rate, because it will allow more equitable distribution of revenues among the producers, gatherers, and transporter.

Second, our eight-point plan addresses Federal regulation, taxation, and management. Much of the energy reserves in the West are located on Federal land. Federal land management agencies must identify those lands that are suitable for oil and gas development prior to leasing.

Now, on the economic front, I supported the extension to the nonconventional fuels tax credit. This included reinstatement of tight sands as a part of the tax credit.

Third, clean-air alternatives. We have made great strides in recent years in improving the air quality along the Front Range. The alternative vehicle fuels and clean coal technologies are an important component of our clean-air program. Compressed natural gas, propane, methanol, ethanol, and oxygenated fuels can have a positive impact on vehicle emissions and air quality.

I have also established an alternative fuels task force to identify policy options encouraging vehicle and fleet conversions to alternative fuels.

And finally, the fourth component of our eight-point plan focuses upon State regulation, taxation, and promotion.

Over the past 4 years we have worked with the industry—the energy industry to review, on a periodic basis and streamline where appropriate, the environmental regulatory process, while not sacrificing environmental quality. We have addressed the both State and Federal issues. While this effort may not solve every problem, it provides a regular channel of communication between the regulators and those who are regulated.

The Gas Policy Reform Act, S. 662, is largely consistent with the oil and gas plan we have outlined for Colorado. And I would like to comment on the major provisions of each section.

First, market development. The first section focuses on ways to promote new uses for natural gas by providing for research, development, and market incentives for gas air-conditioning, vehicle fuels, and power plant co-firing. Probably the most important activity which the Government can pursue with the gas industry centers on expanding the market for natural gas. Given our significant reserves of coal bed methane, there will be an adequate product for expanded markets on the West Coast and the Midwest.

And several proposals in the legislation are consistent with the actions already underway in Colorado. Specifically, Colorado Public Utilities Commission has deregulated compressed natural gas for transportation purposes, and RTD is currently testing methanol buses. It is my hope that section 1007 will provide funds to the Urban Mass Transit Authority to expand this demonstration project to test other alternative fuels and establish performance criteria.

Now, over the past several years, we have discussed with our own congressional delegation the possibility of a major Federal alternative fuels demonstration project at the Denver Federal Center. With the large concentration of Federal employees and vehicles at this facility, a demonstration project would be visible and fuel-efficient.

With regard to private fleets, any programs designed to lower the front-end conversion costs will further enhance the market penetration of alternative fuel. In Colorado, the legislation is pending to increase the per-vehicle tax credit from $200 to $1,000 through a $1.00 increase in the emission inspection fee. This will allow fleets to invest in alternative fuels at 50 cents on the dollar. A revolving loan program under the bill would significantly enhance this effort.

Last year, we dedicated the first alternative fuels fueling station in Colorado. We also built the first conversion facility in the Rocky Mountain region. Section 1009 would help us establish a training and certification program to train the labor force for this growing industry.

Several sections in the bill establish research and development efforts, which could enhance current activities. The Solar Energy Research Institute in Golden has begun research on biomass conversion to vehicle fuels. This legislation could expand this effort at the nation's premier renewable energy research facility. A research and demonstration program for the co-firing of natural gas in power plants—coal-fired power plants is also proposed. A portion of the $20 million in grants received by Colorado projects last year under the Department of Energy Clean Coal Technology Program focused on gas co-firing. The program contained in the bill could transfer the results of these tests to other plants in Colorado.

Now, in order to minimize the environmental disruption, it is important to expand the production from existing formations, as well as nonconventional sources. Section 1012 could provide technical and financial assistance in the horizontal drilling and other enhanced recovery methods. A significant portion of our oil supply problem could be handled through increased production from existing fields.

Finally, summer peaking, caused by air conditioning demands, creates much of the demands for electricity in eastern Colorado. Improved technology for gas cooling in residential and commercial applications could result in fuel switching, and reduce the need for future peak power production facilities. I hope that the Solar Energy Research Institute and our universities will be part of this significant research effort.

Let me speak about regulatory issues. Sections 1016 to 1024 address regulatory issues, including provisions to allow natural gas

producers to be paid for using their fields to store gas for peak periods and requiring Federal regulators to examine natural gas import proposals carefully to ensure that they compete fairly with domestic producers.

It is important to level the playing field between domestic producers and foreign competitors. For this reason, I contacted our congressional delegation during the negotiations on the Canadian Trade Agreement. It was our concern that many Rocky Mountain gas suppliers were being placed in unfair competition with Canadian producers. This is primarily due to the lack of regulatory diligence and environmental guidelines on gas produced in Canada. It is important that we not alter—that we not enter into trade agreements which place our producers at a competitive disadvantage based on differences in values and environmental priorities.

It is also not our intention to support a pricing structure that is artificial or sends false market signals. We advocated the abolishment of the artificial ceiling prices in the resolution of the NTL-5 issues. Now, rates must be structured to allow incentives for system and management efficiencies. However, the ultimate goal must be to avoid duplicative pipeline systems and maintain reasonable costs for the consumer.

In general, rates should reflect the costs of providing service to a particular customer category; cross-subsidies between sectors should be avoided. Similarly, investments in new or expanded systems should be recovered in the rate base; however, the customer should not be penalized for poor business decisions on the part of the supplier.

Regulatory delay is also an important aspect to governmental intervention. Decisions should be made by the Federal Energy Regulatory Commission within a reasonable time frame. Delays can cause both higher costs and public inconvenience. While we agree that reasonable time frames should be imposed for final or modified decisions, the important decisions must not be automatic. It is critical that FERC be adequately staffed to review proposals on a timely basis and minimize the amount of decisions that become final without adequate oversight.

We also support open access to pipelines as a way to minimize the amount of pipeline construction necessary to reach new markets. Similarly, joint pipeline tariffs for producers utilizing more than one system to reach that market will greatly reduce producers' transportation costs.

I would like to speak about accelerated pipeline construction. A major theme of S. 662 in sections 1025 to 1030 focuses on accelerated pipeline construction. Specifically, it discusses the removal of regulatory barriers to allow competition in setting prices and expanding pipeline networks into new markets. I have been supportive of the efforts of several companies to expand the pipeline system in western Colorado. However, I have also stressed that such expansion be both economically efficient and environmentally sound. In addition, it is important for the public and local governments to have an opportunity to review these expansion plans in detail.

For that reason, I have recommended that these projects consider the Colorado Joint Review Process as a means of coordinating

both the permitting and the public review processes. The same CJRP can provide the opportunity to customize and streamline the Federal, State, and local government permit process without sacrificing the very important provisions of the National Environmental Policy Act. I urge this committee to consider the format provided by the Colorado Joint Review Process in evaluating ways to expedite the regulatory process.

Finally, as new pipelines are proposed, the provisions of NEPA should not be overlooked. Specifically, for new pipelines using an existing right-of-way, a preliminary review should be made of the impact of the existing right-of-way—of the existing pipeline to determine whether or not additional environmental assessments are necessary. FERC should not be the sole arbiter of this decision. It should be done in consultation with the affected State and local government entities. FERC should not be allowed to preempt State and local regulations for the sake of expediency. A third-party review of the environmental analysis could be an acceptable way to expedite the process if the criteria are mutually acceptable to FERC and to the affected government.

Studies. The Office of Technology Assessment studies proposed under sections 1031 and 1032 are important. They assess global trends and barriers to increase natural gas use, which are critical to expanded market penetration.

In conclusion, S. 662 will dramatically transform the nation's natural gas industry. It will also expand the marketability of an important Colorado resource. Expanded development in Colorado should occur in a manner that minimizes the financial impact to the consumer and the environmental impact to the land. Colorado State government is available to work with you, Senator Wirth, and the committee in integrating these goals for a more secure energy future. Thank you.

Senator WIRTH. Governor Romer, thank you very much for that very comprehensive and encouraging statement. We look forward to working with the State of Colorado as we have in the past.

I believe that this resource and your being here adds the momentum to our efforts to really increase the use of this pervasive resource, this domestic resource, this clean resource, and this relatively cheap resource; one that in this day and age, with the Persian Gulf situation right behind us, we certainly want to remember that national security is a direction which we must go with energy policy.

I thank you very much for being here. I greatly appreciate your input. We will be getting back to you in particular with your reference to the Colorado Joint Review Process. I was just talking to counsel here. We would like to get some more information on that and see if perhaps there are themes in that that might be adopted to the legislation in our effort to speed up the regulatory process.

Governor ROMER. Yes. I think this is an area where we just bring good economics and good environmental policy together. I thank you for your leadership.

Senator WIRTH. Thank you very much, Governor Romer.

Our second panel this morning includes four very distinguished witnesses who I hope will come join us right now: Mr. Del Hock the chairman, president, and CEO of the Public Service Company of

Colorado; Mr. Tom Vessels, president of the Independent Petroleum Association of the Mountain States; Mr. Fred Julander, of Julander, Platt, Nelson and Associates in Denver; and Mr. Jon Whitney, president and chief executive officer of Colorado State Gas in Colorado Springs. Gentlemen, if you might come up and join us.

As these gentlemen are taking their seats, let me just very briefly point out the history of this legislation. It came out of a session that a number of us had soon after the Iraqi invasion of Kuwait. I have had an energy advisory group for a number of years and we meet together from time to time, and we had a very interesting luncheon session early last fall.

At that time, the concerns about the cutoff of foreign oil, the concerns about the Clean Air Act, the concerns about our own domestic economic situation were all part of the luncheon discussion. Out of that came a resolve to see if we might get together three competing interests that in the past have really spent maybe as much or more time going after each other as they have working together in the natural gas industry.

The producers, the distributors, and the pipelines have tended to be in opposite corners of the natural gas industry, working many times against each other, rather than with each other.

Coming out of that lunch came a resolve of the leaders of those groups, particularly the four gentlemen who are with us here today, to see if we might figure out not only how to resolve our differences, but to come up with a template that would, in fact, encourage both markets and an acceleration of the regulatory process.

And out of that came this piece of legislation, which my staff has been working on with these staffs for many, many months. It was introduced about a month ago.

Now, the energy bill is moving through the Congress very rapidly, and we are currently in a situation where I suspect we are going to be marking that up in April and May.

So the timing of this session here today is absolutely crucial, and having the benefit of your wisdom and perspective and having the opportunity for the committee to better understand the perspective of Colorado in its deliberations. So we thank you again very much for being here.

I know, Mr. Hock, that you have a pressing time frame, and if it is all right, maybe we could ask you to go first. I would point out that we will, of course, include all of your statements and supporting material in full in the record and would encourage you to summarize in any way you think would be most appropriate.

Mr. HOCK. Thank you very much.

STATEMENT OF D.D. HOCK, CHAIRMAN, PRESIDENT, AND CHIEF EXECUTIVE OFFICER, PUBLIC SERVICE COMPANY OF COLORADO

Mr. HOCK. Thank you, Senator, and thank you for the opportunity to be here this morning, and thank you also for providing the leadership that did bring the various segments of the natural gas industry together to assess this problem from a Colorado perspective.

As was indicated in the introduction, I am chairman, president, and CEO of Public Service Company of Colorado, which serves approximately 75 percent of Colorado's 3 million people with both electricity and gas.

Important to this hearing is the fact that we also have two wholly owned subsidiaries directly involved in the natural gas business beyond our natural gas distribution business of Public Service Company. One is Western Gas Supply Company, known as WestGas, which is a gas transmission pipeline company. It is among the 50 top pipelines in the country, and has operated in Colorado since 1925, and has some 2,000 miles of pipeline in the State of Colorado.

Important to the efforts addressed by this bill is the fact that WestGas, in partnership with two others, is involved in the proposed TransColorado pipeline project in western Colorado, a 300-mile pipeline that will carry natural gas from our reserves in Colorado to both the California and Midwest markets.

Another of our companies is Fuel Resources Development Company, known as Fuelco. It is an oil and gas exploration, production, and marketing company which owns production in nearly 600 oil and gas wells in the Rocky Mountain region, and in its marketing role has supplied up to 5 billion cubic feet per day of natural gas—or per month, I should say, to 46 customers off of pipelines in the State.

Fuelco, I might mention, related to the use of our resources, is presently involved in a project known as Synhytech in the Pueblo area, which will utilize landfill methane to produce clean diesel, another part of our efforts to address every resource we can in Colorado, both from an environmental and economic point of view.

We have also joined with two other companies that are at this table with me this morning to form Natural Fuels Corporation, the purpose of which is to build the infrastructure and to develop the market for compressed natural gas as a transportation fuel for fleet vehicles.

Therefore, the interest, from the point of view of the companies I represent, covers every aspect of the legislation proposed in S. 662, from distribution, gas transmission and production, and the use of natural gas as a transportation fuel, and also the technologies and the research and development that is proposed in relationship to the use of natural gas on the electric side of our business.

As has been indicated, one of the important parts of this legislation, I believe, is the fact that the Rocky Mountain region has an abundance of natural gas reserves, nearly 20 percent of the proven reserves in our country, and we are only today providing 8 percent of the gas needs of our nation. There is clearly an opportunity to utilize a resource, an important resource for those markets that are hungry for natural gas.

The problem we face is that we do not presently have the infrastructure that is necessary. That infrastructure needs to be built in a timely manner, and we also need some economic incentives to do that, and we need to remove some regulatory barriers that delay construction. All of those matters, of course, are addressed in S. 662.

I want to say before addressing any specifics that our company enthusiastically supports the efforts of both Congress and the ad-

ministration to develop a comprehensive and effective energy strategy which will, in fact, enable our Nation to move toward energy independence, and we believe, as a part of that strategy, natural gas must play a very key role, and we believe that S. 662 addresses what needs to be addressed in that regard.

I want to spend most of my time this morning on one part of the bill, that relating to vehicular natural gas. We are particularly supportive of those provisions because we believe the use of vehicular natural gas is one of the most important options we have to reduce dependence upon foreign sources.

It is interesting to note a fact that I really seldom reflect on, but one that is very important, and that is that 65 percent of all petroleum products consumed in the United States are used in transportation. Clearly, we have a tremendous opportunity to use natural gas in a way which will reduce foreign dependence.

In addition to that, natural gas, of course, is our cleanest fossil fuel, and it will enable us to have added value in terms of addressing the air quality problems that we face in many of our major cities.

Our company has been involved in research on vehicular natural gas for many years, and after a very comprehensive study completed last year, we concluded that there is clearly a very large potential market for the use of VNG in fleet vehicles. In collaboration with two other companies, that as I indicated earlier, are seated at this table, we did establish Natural Fuels Corporation, the purpose of which is to develop and build the infrastructures for fueling stations, conversion centers, and maintenance facilities.

As the Governor indicated, we have now opened several of those facilities in Colorado. And the market is beginning to develop, as it is in other sections of the company through similar efforts. But it is also clear that the full utilization of natural gas as an energy resource will not be accomplished in this arena in a timely manner unless we enact the provisions proposed that in S. 662.

Even with the incentives in the bill, we will not be able to take full advantage of natural gas as a vehicular fuel until we can move beyond the fleet vehicle market. And that requires something else that is in the bill and is very important, and that is research and development.

We must develop advanced storage systems. We must develop the necessary combustion engine modifications so that we will have economically viable natural gas vehicles for all segments of the market. We can then send the signal to Detroit that they should build single-fuel vehicles, and if we do that, we will then be able to fully utilize the advantages of natural gas in the transportation arena.

We also support the other research and development efforts that are proposed in sections 1011 through 1014. I want to particularly mention our support of the new source review requirements in section 1014 of the bill.

As an electric utility, this is a very important provision. It is very clear that no electric utility will willingly take the risk of using new technologies for either natural gas or clean coal without the assurance that they can move forward with life extension programs, and without those life extension programs, we will lose an-

other energy resource, an important one, that is, repowered power plants.

We support the provisions for accelerated pipeline construction. We believe those provisions are both important and necessary, and we particularly believe that the provisions will enable the industry to construct the pipelines without creating any risk that environmental concerns will not be adequately addressed. We believe the bill adequately addresses that problem, and that we can move forward on the basis proposed.

In terms of regulatory issues, there will be some disagreement about what is proposed in terms of the pricing of natural gas. And while there may well be some price increases in the near term, I believe that we have to take a broader view. We also have an obligation to assure that we have an adequate supply. And without it, the economic incentives that are proposed so that we can move more in the direction of a market-driven pricing for natural gas, I do not believe we will develop this resource in a timely way.

It is important, however, as we look at regulation, to recognize that any departure from cost-of-service pricing must include the necessary regulatory oversight controls, which I believe are addressed by the zone of reasonableness provision in section 1016.

Finally, let me close by saying once again that we believe it is most important that we take advantage of this great natural resource that we have, natural gas. I think as the Senator has indicated, the events of the past several months should convince us that it is now time in this Nation that we develop an energy strategy, an energy policy, and I firmly believe that natural gas must be at the center of that strategy or policy if we intend to achieve its most important objective, which is energy independence.

Thank you for the opportunity to testify this morning.

[The prepared statement of Mr. Hock follows:]

PREPARED STATEMENT OF D.D. HOCK, CHAIRMAN, PRESIDENT AND CHIEF EXECUTIVE OFFICER, PUBLIC SERVICE COMPANY OF COLORADO

My name is D.D. "Del" Hock, Chairman, President and Chief Executive Officer of Public Service Company of Colorado, an electric, natural gas and thermal energy utility serving approximately 75 percent of Colorado's three million people.

I also serve as Chairman of two wholly-owned subsidiaries:

Western Gas Supply Co. ("WestGas"), is a natural gas gathering, processing and transportation company, which is ranked as one of the top 50 pipeline companies in the nation. Operating since 1925, WestGas is the largest intrastate pipeline company in Colorado with more than 2,000 miles of pipeline.

WestGas is a partner in the proposed TransColorado project to build a 300-mile pipeline to carry approximately 300 million cubic feet of gas per day from the Piceance Basin in northwestern Colorado to California and Midwestern markets through connections with other interstate pipelines.

Fuel Resources Development Co. ("Fuelco"), is an oil and gas exploration, production and marketing company which owns production in nearly 600 oil and gas wells in the Rocky Mountain Region. In its marketing role, Fuelco has supplied up to five billion cubic feet of natural gas per month to 46 customers off of 12 open access natural gas pipelines.

Fuelco is also engaged in the development of a new technology called Synhytech designed to produce clean-buring diesel fuel from methane. Our pilot project is using landfill methane.

In addition, we have joined with two other companies to form Natural Fuels Corporation to build the infrastructure and develop the market for compressed natural gas as a transportation fuel for fleet vehicles.

Therefore, our interest in the subject matter of the legislation proposed in S. 662 involves every segment of the natural gas industry—local distribution, gas transmis-

sion and production, and the use of natural gas as an alternative transportation fuel. We are also interested in issues related to natural gas and electric heating technologies and the use of natural gas as a boiler fuel for existing steam generating units.

The Rocky Mountain region has an abundance of natural gas reserves—nearly 20 percent of the nation's proven reserves. Yet, we supply only eight percent of the nation's natural gas needs from our region. These reserves can provide an important new source of supply to the growing markets in California and the Midwest; however, this cannot happen without the necessary infrastructure in place. And this infrastructure will not be built in a timely manner unless there are some economic incentives to do so and some of the regulatory barriers to pipeline construction are removed.

We strongly support the efforts of both Congress and the Administration to develop a comprehensive and effective energy strategy which will enable our nation to move toward energy independence. Further, we believe natural gas, an abundant domestic resource, which is one of our most environmentally clean energy resources, must be a significant part of any successful energy strategy. In order for us to take advantage of this important energy resource, we need to take several important steps which are addressed in S. 662.

VEHICULAR NATURAL GAS

We are particularly supportive of those provisions in S. 662 addressing the use of natural gas as a motor vehicle fuel. Since it is the transportation sector which uses nearly 65 percent of all petroleum products consumed in the United States, the development of natural gas as an alternative transportation fuel is clearly an action which can have more direct impact on reducing our dependence on imported oil than almost any of the other options available to us.

In addition, the environmental advantages of natural gas as a motor vehicle fuel can play a significant role in improving the air quality in our major cities.

Our Company has been involved with the research and development of natural gas as a motor vehicle fuel for several years. After completing an extensive study, we concluded there was clearly a large potential market for the use of VNG in fleet vehicles. Therefore, in collaboration with two other companies, we formed Natural Fuels Corporation to develop and build the infrastructure for fueling stations, conversion centers and maintenance facilities. Even though the market is beginning to develop as a result of this and similar efforts in other sections of the country, it is clear that the full utilization of this important energy resource will not be accomplished in a timely manner without the enactment of S. 662.

Even with the incentives included in S. 662 for promoting the use of VNG, we will not be able to take advantage of the full potential of this resource unless we can move beyond the fleet vehicle market to all other sectors of vehicle transportation. It is important to note that the natural gas distribution infrastructure necessary to meet the added demand from such a new market is already in place. However, we cannot develop this broader application of VNG without some new technology such as advanced storage systems and combustion engine modification. This technology will make single fuel natural gas vehicles economically viable for all segments of the market, and will thereby motivate the automobile manufacturers to build such vehicles. Therefore, it is essential that we encourage more research and development on VNG technology as is proposed in Section 1010 of S. 622.

Finally, I want to particularly endorse the provision in Section 1004 relating to state regulatory jurisdiction of VNG. It is vitally important to the continued and successful development of VNG that we minimize any regulatory impediments. Therefore, we must give to the state commissions the flexibility to determine what regulatory requirements, if any, are necessary for the sale and transportation of VNG.

OTHER RESEARCH AND DEVELOPMENT

There are many other important opportunities to expand the use of natural gas. However, like VNG, these applications will not be developed without additional research and development. The incentives and programs provided by Sections 1011 through 1014 of S. 662 will be an essential part of creating the necessary momentum in the private sector to do the necessary research and development for these new technologies.

NEW SOURCE REVIEW REQUIREMENTS ("WEPCO FIX")

As both an electric and natural gas company, we are strongly supportive of the provisions in Section 1014 of this bill exempting pollution control projects from the new source performance requirements of the Clean Air Act. Unless a utility can be assured that such a project will not result in a new source review, it will not willingly take the risk of developing new pollution control technologies using either natural gas of clean coal. As a result, some life extension programs which can provide low cost electric generating capacity will not be implemented.

UTILITY BOILER EXEMPTIONS

We are also supportive of the provision exempting utility boilers using natural gas as a fuel from NO_x emission standards. Without recognizing the environmental advantages of natural gas as a boiler fuel and removing as many impediments as possible to encourage this use, we will not be able to maximize this important application of natural gas.

ACCELERATED PIPELINE CONSTRUCTION

In order to develop the full potential of our natural gas resources, we must do everything possible to expedite the construction of additional pipeline capacity. This is particularly true in states such as Colorado with large underutilized reserves of natural gas. This will not happen unless we remove the regulatory barriers which not only delay construction, but also escalate the ultimate cost of these pipelines. I believe the provisions included in S. 662 will enable the industry to construct pipelines expeditiously without creating any risk that environmental concerns will not be adequately addressed.

REGULATORY ISSUES

While there are clearly some differences of opinion within the various sectors of the natural gas industry regarding some of the provisions included in the "Regulatory Issues" section of S. 662, it is clear, I believe, that some regulatory changes are necessary in order to accelerate the development of our natural gas resources. I would suggest that while a traditional cost of service approach may, in the short term, result in somewhat lower process, we must also address the long term objective of an adequate and deliverable natural gas supply. Without some economic incentives based upon market driven pricing, we will not be able to adequately meet this broader objective within the necessary timeframe. It is important to recognize that any departure from cost of service pricing must include the necessary regulatory oversight and controls which are addressed by the "zone of reasonableness" provision of Section 1016.

CLOSING

Finally, I want to emphasize my firm belief that we must take full advantage of the vast natural gas resources we have in the United States. Surely the events of the past few months should convince us of the absolute importance of finally developing and implementing an energy strategy. It is just as clear that unless we take full advantage of our vast natural gas resources as a key part of that energy strategy we will not succeed in achieving the most important goal of that strategy—energy independence.

I appreciate the opportunity to share with this Subcommittee my views on this most important subject.

Senator WIRTH. Mr. Hock, thank you very much. I know that you have a very constrained schedule and if you want to take off, by all means feel free to do so. I have one question that I wanted to direct at you in particular.

Mr. HOCK. Yes.

Senator WIRTH. And I think you are probably familiar—and, if not, maybe you can answer this for the record—with the proposals of the administration related to the reorganization of FERC.

Mr. HOCK. Yes.

Senator WIRTH. The administration has proposed that FERC become part of the Department of Energy, and I was wondering if you had any reaction to that proposal for reorganization.

Mr. HOCK. Well, while I think that it probably can function either way, it would be my preference that we do not move it to a single administrator in the Department of Energy. I believe that the present arrangement we have with some of the proposals that encourage FERC to act more expeditiously in terms of the matters that need to be addressed is a better approach than revamping that whole structure. I have concern that that will not, in fact, take us in the direction that we need to go.

Senator WIRTH. Related to that, what are the major impediments that you have at the Public Service Company in terms of expanding markets for natural gas? Are they regulatory impediments or are they market impediments?

Mr. HOCK. Well, there are some of both, of course. We are less involved at the FERC level than some of the other companies represented here in that ours is an intrastate pipeline. The project currently involved in that I mentioned is under the jurisdiction of the FERC.

But we are also involved because we are the customer of those pipelines that need to build the infrastructure so that we can have the supply that we need. And it is clear that there is undue delay, in my view, as we try to move forward on projects that are needed.

I think we have today a system that provides incentives for delay, rather than incentives to expeditiously move forward in a way that is not harmful to the parties at interest. I think much of that delay is really counterproductive, and I believe that what is proposed in the bill in terms of eliminating some of those barriers without eliminating the regulatory oversight—because I do not think that is what is being proposed—would be very helpful in terms of moving this whole process along.

And I think one of the great concerns that I have is the focus on timeliness. Too often we assume that we have more time than we really do, in my view, to build the infrastructure, to get that supply in place and to really address the markets that are there. And we do not have much time.

I am serious when I suggest that natural gas must be an important part of our national energy strategy. And as this map would suggest, if you look at the infrastructure across the country, we do not have the infrastructure in place in the western United States, and yet we have, as I indicated, one of the major sources of supply of natural gas. And we simply must move forward as quickly as possible to develop that resource.

Senator WIRTH. Well, Mr. Hock, thank you very much. I know you have to go, and there are a number of your distinguished associates here, and if we have questions of the Public Service Company, I am sure that they can answer them.

Mr. HOCK. I will leave my proxy with them.

Senator WIRTH. Thank you very much, Mr. Hock. If we might proceed, and have each of you present your testimony and then get to questions, if that is all right. We will go to Mr. Vessels to Mr. Julander to Mr. Whitney. Thank you very much for being here.

STATEMENT OF THOMAS J. VESSELS, PRESIDENT, INDEPENDENT PETROLEUM ASSOCIATION OF MOUNTAIN STATES AND PRESIDENT, VESSELS OIL & GAS CO., ACCOMPANIED BY FRED C. JULANDER, PRESIDENT, COLORADO OIL & GAS ASSOCIATION AND PRESIDENT, JULANDER PLATT NELSON, INC.

Mr. VESSELS. Thank you. Thank you, Senator, for giving us the opportunity to address issues that are very important for us here in Colorado and in the Rockies.

For other parties here, my name is Thomas J. Vessels. I am president of the Independent Petroleum Association of Mountain States. We have approximately 900 members represented in all the major natural gas-producing States in the Rocky Mountains. IPAMS, as we refer to it, has been involved in litigation at the FERC in the past on behalf of its producer-members.

In my private capacity, I am president of Vessels Oil and Gas Company, a natural gas-producing, gathering, and processing concern, and reside here in Denver, Colorado.

I am going to present testimony jointly with Fred Julander.

Mr. JULANDER. Thank you. Senator, thank you. Also for others here, I am Fred Julander. I am president of the Colorado Oil and Gas Association, the trade association of Colorado oil and gas producers that is aligned in many cases with IPAMS in natural gas issues. The Colorado Oil and Gas Association is the host and sponsor of the largest Rocky Mountain natural gas marketing conference. We are very active in the natural gas industry.

I am also president of Julander Platt Nelson, an exploration and consulting firm that specializes in energy and the environment. About 5 years ago, we decided to focus on one energy source, and that was natural gas. It seemed to us that it was an underutilized resource that was in abundant supply and one that had inefficiencies in place which, if cleared away, could make it a tremendous business—provide a tremendous amount of benefit for society.

It is of great pleasure to be here at a table with CIG and Public Service, a public utility and a major interstate pipeline, in front of you, Senator Wirth, and have this kind of attention focused on the natural gas business. We think this is what it deserves. We appreciate your leadership, and we appreciate working with the other segments of the industry in order to build the natural gas business. This is what is needed and has been needed for a long time. Thank you.

[The prepared statement of Mr. Vessels and Mr. Julander follows:]

PREPARED STATEMENT OF THOMAS J. VESSELS, PRESIDENT, INDEPENDENT PETROLEUM ASSOCIATION OF MOUNTAIN STATES, ACCOMPANIED BY FRED C. JULANDER, PRESIDENT, COLORADO OIL & GAS ASSOCIATION, AND PRESIDENT, JULANDER PLATT NELSON, INC.

My name is Thomas J. Vessels and I am a resident of Denver, Colorado. I would like to thank the United States Committee on Energy and Natural Resources for taking the time and effort to convene a hearing in our region. I am currently serving as President of the Independent Petroleum Association of Mountain States ("IPAMS"). IPAMS has approximately 900 members including producers from the states of North Dakota, South Dakota, Montana, Wyoming, Nebraska, Colorado, Utah, Nevada and New Mexico. IPAMS has a history of natural gas involvement including litigation and a protest filed with the FERC and testimony to the FERC regarding natural gas rate reform.

In my private capacity I am President of Vessels Oil & Gas Company, a closely held family owned corporation. We have been in the petroleum business since the early 1930's. Currently we operate gas wells, pipelines, and a gas plant here in Colorado. I have in the past given testimony to the FERC and the House Commerce Committee on Energy and Fossil Fuels.

Today I will with pleasure present testimony jointly with my colleague, Fred Julander.

My name is Fred C. Julander and I am a resident of Denver, Colorado. I am pleased to be invited to testily before you and very pleased that you are here.

I am President of the Colorado Oil & Gas Association ("COGA") which represents over two hundred participants in our state's oil and gas business. COGA is very active in natural gas affairs including being annual sponsor and host of the "Colorado and Rocky Mountain Natural Gas Strategy and Meeting Conference" which attracted 450 gas industry members last year.

In my private capacity, I am President of Julander Platt Nelson, Incorporated, a privately held consulting and exploration firm that specializes in energy, natural resources and the environment. Our staff consists of geologists, engineers and MBA's. We explore for natural gas, have a joint venture in compressed natural gas vehicles (CNG), and do research on the natural gas industry including publication of the "Rocky Mountain Report on the Natural Gas Industry."

It is a pleasure to be here before you, and to be here with Tom Vessels.

COMMENTS ON S. 662

As you know, the Independent Petroleum Association of Mountain States ("IPAMS"), the Colorado Oil & Gas Association ("COGA"), along with Colorado Interstate Gas Company ("CIG"), Public Service Company of Colorado ("PSCo"), and other individuals, has been engaged in an effort to develop comprehensive natural gas legislation. This effort has come to fruition with the introduction of S. 662, The Gas Policy Reform Act, by Senator Wirth.

The overall goals are to stimulate demand and enhance production (see Sections 1004–1014); streamline the pipeline permitting/construction process (see Sections 1025–1030); reform pipeline rate design (see Sections 1015–1022); and enhance domestic wellhead prices and competitiveness (see Sections 1023–1024).

Producers will realize long term benefits from enhancement of the natural gas market and the Federal Energy Regulatory Agency ("FERC") and its regulatory system generally. In addition, there are several measures designed to provide immediate, direct benefits to producers:

1. Producer demand charges for gas supply security will be recovered "as billed" in pipeline (merchant service) demand charges, so long as the customer has a reasonably competitive (transportation) alternative. This will allow those producers who wish to sell to the traditional pipeline buyer to bargain for a premium for reserve dedication.

2. Natural gas import approvals are conditioned on action to redress competitive disparities, including those deriving from different rate structures applied to imported and domestic gas. This ensures a "level-playing field" for domestic independent producers.

3. Pipelines are authorized (under FERC regulation) to offer joint tariffs where producers have to utilize more than one system to reach the market. This "one-stop" shopping will greatly simplify making transportation arrangements and reduce producers' transactions costs.

4. The goals of FERC's pipeline rate reform policy are transformed into statutory mandates. "Rates shall be designed to efficiently allocate capacity, maximize throughput, eliminate cross-subsidies among customer classes and between transportation and merchant services, reflect any material distance related variation in the cost of providing service, and appropriately unbundle distinctive services." Those among you who have followed the FERC's deliberations will translate this broad language into such specific measures as: shifting from modified fixed-variable to full fixed-variable rate design, eliminating the 100% load factor interruptible transportation service rate, peak pricing accounting for seasonal demand and other factors, mileage-based rates where appropriate (including backhaul discounts), and elimination of shipper subsidies to pipeline services (e.g., storage, upstream transportation, gathering) not utilized (or even available sometimes). Of course, the "proof is in the pudding" in this area, and producers will have to redouble their efforts in pipeline rate matters. But, the FERC will be precluded by statute from approving settlements which depart

from these standards. Administrative convenience will no longer justify the failure to achieve the rate reform promises of Order 436.

5. LDC's will no longer be able to "hoard system capacity" because the pipeline service obligation upon contract expiration is eliminated. In return, conversion to transportation service is encouraged by eliminating the automatic abandonment of such service. LDC's have been able, since elimination of the minimum bill, to swing off system supply, take advantage of low spot prices, and yet be able to demand contract service during peak periods (bumping transporters in the process). The result is underpricing of the supply security element to gas reserves because LDC's have free assurance of supply. This reform is the missing piece to the open access puzzle.

I hope you agree that this bill will transform the natural gas marketplace, transportation system and regulatory environment in a fashion which benefits producers, especially independents who lack supply-side market power and regulatory presence. The bill drafting process was an intensive effort undertaken by the natural gas community encouraged by the leadership of Senator Wirth. The task is not completed, however. Those who did not participate in the negotiating sessions from the producer, pipeline or utility industry may see elements they oppose. All of us who participated in the discussions started with wish lists which were trimmed along the way. After years of acrimony between these segments of the industry, some key members of the Rocky Mountain and Colorado gas industry agreed to items which were of mutual benefit in the long run. Hopefully, other parties will see the benefits to the nation as they understand the benefits to our state and our region.

We will show the importance of natural gas to our state and our region and why this bill is important to us by the following exhibits.

MARKET DEMAND

The big picture we wish to present as far as market is concerned contain the following elements:

1. Market demand has not increased for several years (Figures 1 and 2).

2. There is very little market demand in the Rocky Mountain Region when compared to the regional resource base and the markets of other states. Colorado has as large a market as there is in the Rockies and it is minuscule in comparison to other states. It is made up of the front range of urban areas of Eastern Colorado (Figure 3). The region as a whole is a net exporter of gas (Figure 4).

Please see the exhibits describing the reserve potential areas where gas is located in the region (Figures 5, 6.1, 6.2, 6.3, 6.4, 6.5 and 6.6). The activity in the Rockies and Colorado in particular are provided (Figures 7, 8, 9 and 10).

INCENTIVE RATEMAKING OPTIONS AND ACCELERATED PIPELINE CONSTRUCTION

This is a very arcane area of natural gas affairs. Our exhibits will attempt to establish some fundamental points:

1. Pipelines are buying less gas than before (Figure 11).

2. Utilities are buying about the same or less (Figure 1).

3. Industrial customers and electrical generators are purchasing more (Figure 1).

4. The pipeline rate structure belongs still to the time when pipelines were the merchants which they no longer are.

5. We need a new rate structure to allow gas to flow from the Rockies to the regions of increased industrial and power generation.

As an example of one of the greatest scandals in the pipeline industry we provide a schematic map of the Overthrust, WIC, and Trailblazer pipelines as a prime example of what we believe must be overcome (Figures 12 and 13). The rates to get from a major producing region of the U.S.A. to get to the Midwest industrial area may go through as many as six pipelines, three of which were originally intended to operate as one (the Overthrust, WIC and Trailblazer pipelines):

	Transportation Status
Overthrust	Waiting Order
WIC	Settlement and Open Access Files 2-6-90
Trailblazer	Open (311)

Joint tariffs would obviously result in this case especially in pipelines operating in an efficient manner.

To add insult to injury the Kern River Pipeline to California is still not in service after years of delay at the FERC. At least completion of that system is in sight. An

accelerated pipeline construction of this pipeline and others could have helped satisfy the need for customer to producer direct transactions over the pipeline network.

This is all essential for Colorado and the other Rocky Mountain States because major pipeline projects have taken place to increase access by Canadian gas to the U.S.A. We feel the market demand for gas will be secure and grow if Canadian gas and LNG has access to the U.S.A. This will make customers in the U.S.A. secure in the knowledge that there exist plentiful gas supplies for years to come. The problem for the Rockies regarding Canadian gas are two fold:

1. Canadian pipeline expansions and their related systems in the U.S.A. have proceeded while Rocky Mountain pipeline expansion and reinforcement has not (Figure 14).

2. Exports from Canada are increasing into a market that is not expanding (Figures 15 and 16).

3. Rocky Mountain gas is being held back by a domestic regulatory structure while in Canada pipeline expansion is encouraged (See attached Exhibit 16.1 concerning Canadian export strategy). The Canadian suppliers themselves acknowledge on Page 4, Paragraph 2 of Exhibit 16.1 "That the U.S. Mid-continent and Rocky Mountain reserve areas have a long run capability not only to support the Midwest markets, but also to compete for incremental demand on non-traditional market areas *to which they are not now significantly connected.*" (italic by IPAMS and COGA). I would recommend that Exhibit 16.1 be read in its entirety. The Canadian research and strategy described therein will explain why we Rocky Mountain Producers are concerned that our policy makers understand the need for reform of the natural gas transportation system. It is so we can do no more than compete toe to toe with our serious and able competitors.

WELLHEAD PRICES

Demand charges payable to producers and billable to pipeline customers will reward producers who undertake producing gas at the "demand" of the pipeline customer. The fact is simply that the producer is not currently compensated for operating in a way to produce his gas so as to provide the commodity during the period of most important and critical need, the winter time heating season. Pipelines and utilities are compensated for constructing storage fields while the most inexpensive storage field from the customers' point of view, the one from which the gas originally came, is not efficiently utilized by the appropriate economic incentives being provided (Figures 17 and 18).

The current "Rocky Mountain Discount" applied to Colorado and our regional states are not due to our lack of gas but rather due to a large reserve of gas that does not have access to the regions we are closest to (Figures 19, 20, 20.1 and 21).

All the other specific measures in S. 662 we support as they are definitely oriented toward improving the market for natural gas and the available supply of gas.

COMMENTS ON TAX PROPOSALS OF OTHER BILLS

Not only are there many natural gas regulatory road blocks from the past inhibiting the gas industry's efficiency, but there are also various tax penalties from an era of higher petroleum prices and economic activity. These are a real burden for the independents who must devise strategies to work them to their benefit. There are tax incentives for instance that accrue to large major companies and independents that actually do not benefit smaller independents. As the majors leave the Rocky Mountains more and more of the natural gas base economic activity will be left to the independents who will continue to reside here. The items in S. 741 will be extremely important to the Colorado and Rocky Mountain gas production industry and we firmly support S. 741.

COMMENTS ON S. 341, THE NATURAL ENERGY SECURITY ACT OF 1991 AND SENATOR BINGAMAN'S PROPOSED AMENDMENTS THERETO

Regarding S. 341 and Senator Bingaman's amendment, we are in favor where they do not conflict with S. 662. We have not completely analyzed the different nuances of the various proposals and must defer to a later date final comments on S. 341.

Regarding S. 341, Section 10007: We support allowing independent producer cooperatives. We ask that Line 7 of (3) after the colon be stricken: Our concern is that industrial customers have already formed purchasing groups to gain advantages of economic size so as to obtain better terms for purchasing gas. One of the key terms

is price. Prices have fallen considerably. We believe non-major company independent producers should be allowed to join forces with each other for the sake of their own survival. One key element to economic survival is the price you get for your commodity.

CONCLUSION

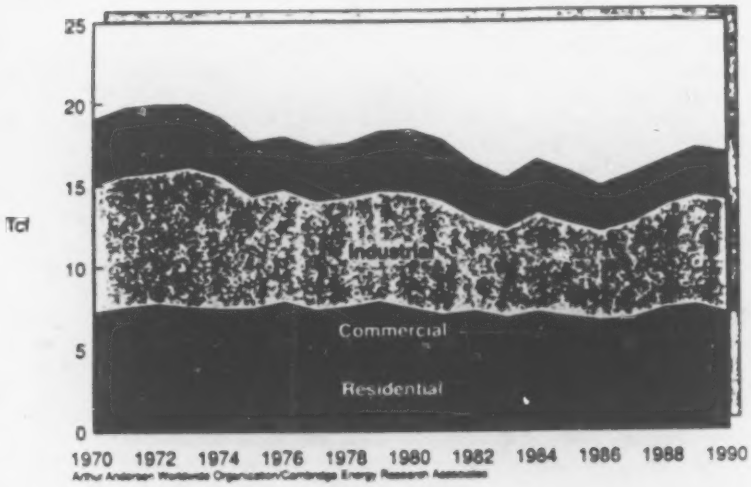
Natural gas is very important to the future of Colorado. Colorado is the headquarters state of the Rocky Mountain gas supply region, which includes the Northern half of New Mexico, the Eastern half of Utah, the Southern half of Wyoming and Colorado. This Rockies region has the third highest conventional potential gas reserves in the United States, some 120 Tcf. However, if unconventional reserves being established by coal bed methane development and horizontal drilling are included, the Rocky Mountain region, in our projections, could have more than 210 Tcf of potential reserves ad become the leading repository for natural gas in the United States—ahead of even the Texas and Oklahoma regions. In addition, there is a vast amount (in excess of 5,000 Tcf or over twenty times present potential reserves) of "not recoverable with present technology" tight sand gas reserves in place in the region which we believe the gas exploration industry will start to learn how to tap within the next ten years.

The oil and gas industry, the gas portion of which is very significant in Colorado because of the high percentage of natural gas reserves versus oil reserves in the state, has suffered attrition since 1982, but is still important to the Colorado economy. The oil and gas extraction industry (SIC 13) has lost 16,220 direct jobs or 56.8% of its employment base between 1982 and 1989 (Figure 22). When using RIMS multipliers to identify both direct and secondary jobs lost, the total loss between 1982 and 1989 climbs to 47,137 jobs. In 1989, direct jobs in the industry stood at 12,325 and direct and indirect jobs at 35,865 out of 1,463,727 total Colorado jobs.

Wages paid in the oil and gas industry are the second highest in the state and were 96.9% higher than the state average in 1989. The energy sector is still more important for Colorado than for the U.S. on the whole, as two times more citizens are employed in this sector in Colorado than in the country as a whole. The Colorado natural gas industry, including both the E&P and distribution segments, is approximately the same size as Colorado tourism and basic manufacturing. Colorado stands to benefit economically and the rest of the country stands to benefit environmentally and economically if the Rocky Mountain region's gas reserves are developed and used in increasing volumes domestically.

Figure 1.

Natural Gas Consumption by End-Use Sector

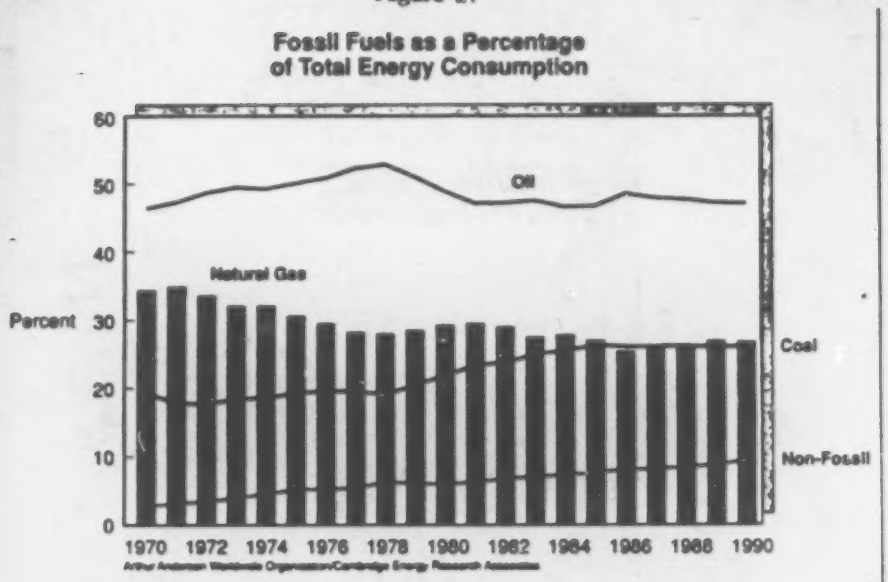


U.S. natural gas consumption declined by 26% from peak consumption in 1973 to 1986, falling from 22.0 Tcf to 16.2 Tcf. Since 1986, when gas consumption reached its lowest level in 21 years, consumption has increased by 2.4 Tcf, about 15%. The decline in demand during the 1970s and early 1980s occurred largely in the industrial and electric utility sectors, which together accounted for a 4.2 Tcf reduction in consumption.

The decline in industrial demand during this period can be attributed to three factors: fuel substitution, structural changes in the economy, and improvements in energy efficiency. Long-term fuel substitution occurred not between gas and oil, but rather from gas to electricity, coal, and waste products. The petroleum refining and paper industries, for example, experienced extensive fuel substitution as well as efficiency improvements. Gas consumption by electric utilities also declined significantly until 1986, with displacement by coal and nuclear generation accounting for most of the reduction in gas demand.

Between 1986 and 1990, strong growth in the U.S. economy, and in particular, substantial increases in industrial output and electricity demand, contributed to a rebound in natural gas consumption. Although most of this increase has been in the industrial sector, as much as half of the growth in industrial gas consumption has been caused by power generation by industrial cogenerators.

Figure 2.



From 1980 to 1986, U.S. natural gas consumption as a percentage of total U.S. primary energy consumption declined from 27% to 23%. The chief beneficiaries of this decline were coal and non-fossil energy sources, which increased over this period. From 1986 to 1989, natural gas reclaimed some of the lost ground as gas consumption increased to 24% of total primary energy use. As a percentage of total U.S. fossil fuel consumption, however, natural gas consumption is still well below its peak of 35% in 1971.

Total oil consumption declined during the first half of the 1980s but increased in the second half so that 1989 consumption of 34.2 quads was the same as in 1980. The decline in consumption attributable to efficiency gains prompted by the oil shocks of the 1970s has slowed since the collapse in world oil prices in the mid-1980s.

Driven by electric utility demand, coal consumption has increased by 9% since 1986 and 23% since 1980. By 1986, coal displaced natural gas as the second largest source of primary energy in the United States. But by 1989, this was reversed by a resurgence in gas consumption.

The rebound in natural gas demand since 1986 is attributable to robust economic growth, increasing demands for power generation, and tightening environmental standards. Increases in natural gas consumption for electric power generation have accounted for substantial growth in the industrial sector, where many new cogeneration facilities have come into service, as well as in the electric utility sector.

Figure 3.

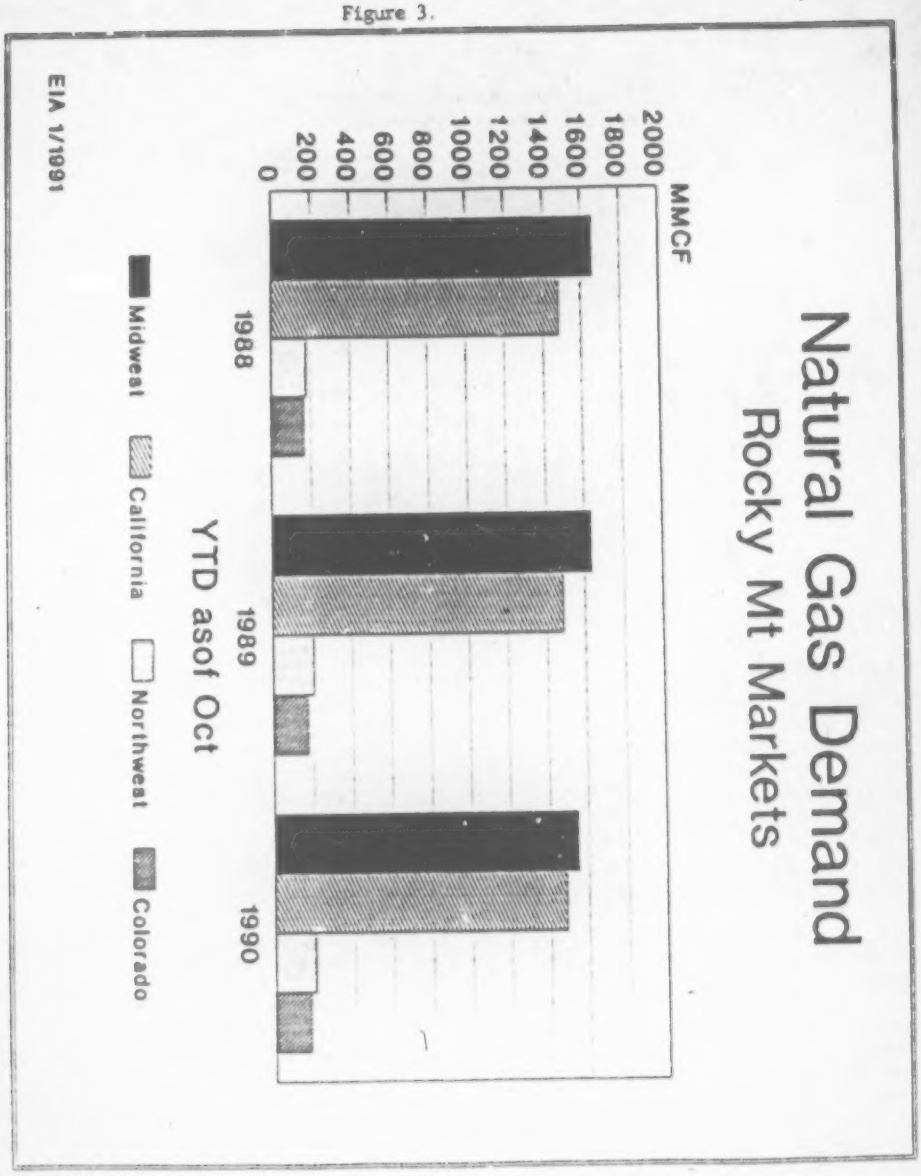
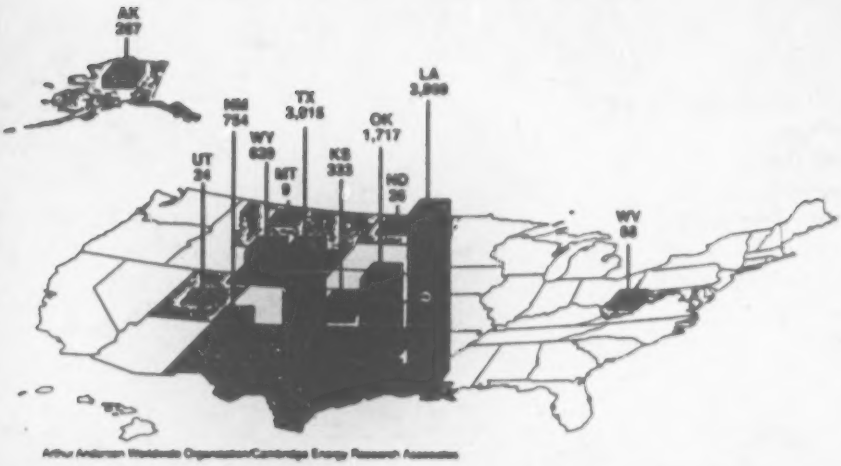

Natural Gas Demand
Rocky Mt Markets
MMCF
2000
1800
1600
1400
1200
1000
800
600
400
200
0
1988
1989
1990
YTD asof Oct
Midwest
California
Northwest
Colorado
EIA 1/1991

Figure 4.

States with Net Marketed Production (Bcf)



Although Texas produces a significantly larger amount of natural gas than any other state, Louisiana accounts for the largest volume of net marketed production since it consumes only 24% of in-state production. Together with Oklahoma, these three states accounted for 75% of total U.S. dry gas production and 80% of net marketed production. The primary markets for supplies from these states were the Midwest and Northeast although West Texas supplies were marketed to California.

The three largest consuming states are Texas, California, and Louisiana, accounting for 37% of total U.S. consumption. For 1989, California consumed five times what it produced and made up for its production shortfall by importing 489 Bcf from Canada and purchasing the remaining 947 Bcf primarily from southwest U.S. sources. The Midwest region and the Mid-Atlantic/Northeast regions accounted for 25% and 17% respectively of total U.S. consumption.

Figure 5.

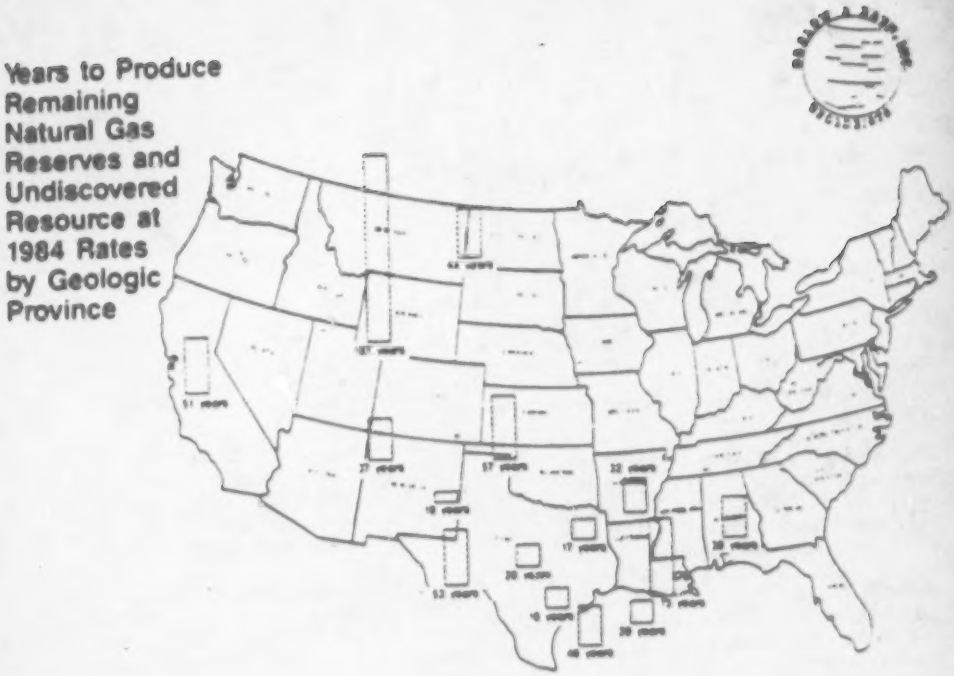
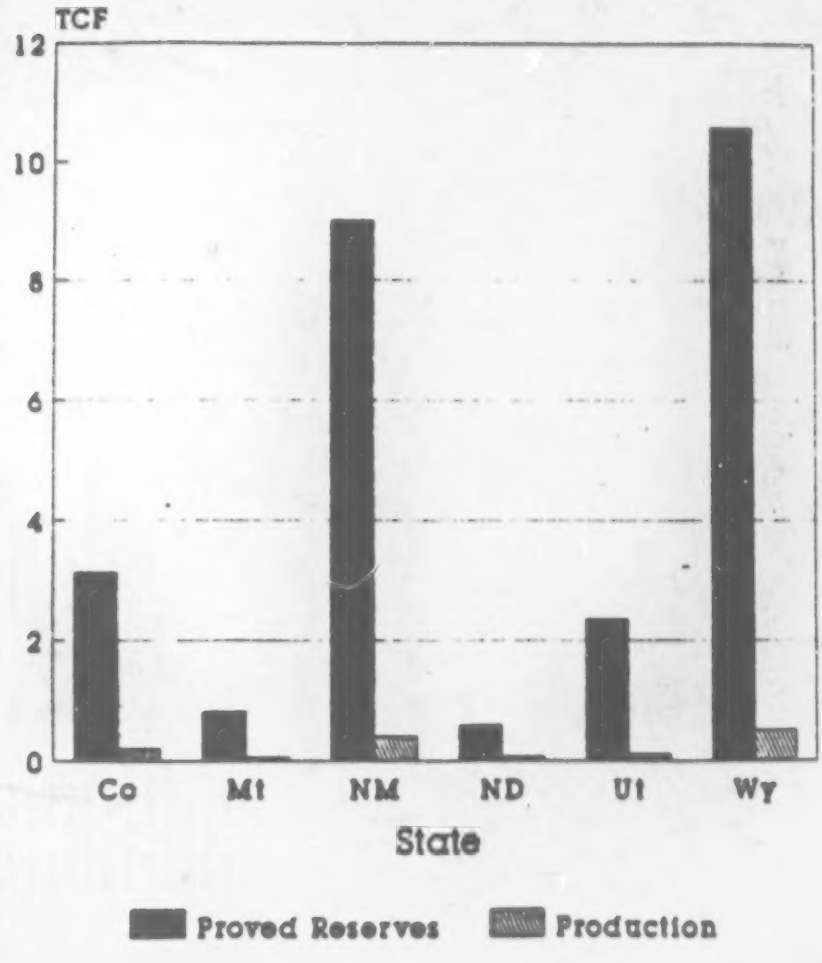

Years to Produce
Remaining
Natural Gas
Reserves and
Undiscovered
Resource at
1984 Rates
by Geologic
Province

Figure 6.

Reserves/Production



Petroleum Independent 9/1989

Figure 6.1
(Gas Research Institute)

Areas Containing Tight Gas Sands

1. Northern Great Plains Province
2. Snake River Downwarp
3. Big Horn Basin
4. Wind River Basin
5. Wasatch Plateau
6. Douglas Creek Arch
7. Denver Basin
8. San Juan Basin
9. Paxton Basin
10. Anadarko Basin
11. Arkoma Basin
12. Ouachita Mountains Province
13. Val Verde Basin
14. Fort Worth Basin
15. Western Gulf Basin
16. Cotton Valley Trend
17. Greater Green River Basin
18. Uinta Basin
19. Piceance Basin
20. Michigan Basin
21. Appalachian Basin
22. Illinois Basin
23. Black Warrior Basin

Figure 6.2

(Gas Research Institute)

ROCKY MOUNTAIN REGION: LOCATION OF RESERVES

Figure 6.3

(Gas Research Institute)

Table 5. Estimated resources of natural gas for provinces of the Rocky Mountain Area, December 1968 (billion cubic feet)

PROVINCE	ONSHORE	OFFSHORE	PROBABLE			POSSIBLE			SPECULATIVE		
	depth	water depth	Min	Most likely	Max	Min	Most likely	Max	Min	Most likely	Max
P-500, Williston basin	0-15,000'		300	1,000	1,500	400	500	600	*	300	500
	15-30,000'								*	*	300
P-510, Powder River basin	0-15,000'		700	1,100	1,500	1,500	2,200	2,700	300	500	700
	15-30,000'								500	1,000	2,000
P-515, Big Horn basin	0-15,000'		400	550	1,000	400	550	1,000	*	*	*
	15-30,000'		100	150	450	500	650	1,300	*	400	700
P-520, Wind River basin	0-15,000'		600	1,250	1,800	1,800	3,550	5,000	*	*	*
	15-30,000'		2,950	3,400	4,250	2,500	3,100	5,100	*	400	700
P-530, Greater Green River basin	0-15,000'		7,900	9,700	12,000	7,200	12,800	20,300	300	3,400	7,000
	15-30,000'		4,500	5,000	5,500	11,400	15,600	20,600	100	2,500	7,500
P-535, Denver basin, Claiborne arch and Las Animas arch	0-15,000'		1,700	3,000	5,000	900	2,100	4,000	*	*	150
	15-30,000'								*	*	*
P-540, Uinta/Piceance basins, Park and Eagle basins	0-15,000'		5,000	7,100	10,200	2,800	4,000	5,500	200	600	2,300
	15-30,000'		200	500	1,500	800	200	800	600	300	2,000
P-545, San Juan Mountains, San Luis/Raton basins, etc.	0-15,000'					800	400	1,000	*	700	1,400
	15-30,000'								*	300	600
P-550, Paradox basin	0-15,000'		50	150	200	500	900	3,000	600	300	700
	15-30,000'								*	*	*
P-555, San Juan basin	0-15,000'		1,000	1,500	2,500	300	500	1,000	*	*	*
	15-30,000'								*	*	*
P-560, Southern Basin and Range province	0-15,000'					*	1,400	5,600	*	*	*
	15-30,000'								*	*	500

*Negligible quantity of natural gas contained.

Figure 6.4

(Gas Research Institute)

Table 5 (continued). Estimated resources of natural gas for provinces of the Rocky Mountain Area, December 1988 (billion cubic feet)

PROVINCE	ONSHORE depth	OFFSHORE water depth	PROBABLE			POSSIBLE			SPECULATIVE		
			Min	Most likely	Max	Min	Most likely	Max	Min	Most likely	Max
P 565, Plateau province,	0-15,000'		*	*	50	*	50	100	50	250	500
Black Mesa basin	15-30,000'								*	*	*
P 570, Sweetgrass arch	0-15,000'		1,800	2,300	3,200	1,400	1,900	2,400	800	1,100	1,350
	15-30,000'								*	*	*
P 575, Montana Foothill Belt	0-15,000'		*	*	100	*	1,000	2,000	*	2,500	3,500
	15-30,000'								*	*	*
P 580, Snake River basin	0-15,000'								100	200	300
	15-30,000'								*	*	*
P 590, Wyoming Utah Idaho	0-15,000'		1,000	2,300	3,400	500	2,400	6,000	1,900	4,000	10,000
Thrust Belt	15-30,000'		3,000	5,000	8,000	800	1,200	3,000	1,000	2,200	4,000
TOTAL, onshore	0-15,000'			29,950			34,250			13,650	
TOTAL, onshore	15-30,000'			14,050			20,750			7,100	
TOTAL, onshore, all depths				44,000			55,000			20,750	
GRAND TOTAL FOR AREA				44,000			55,000			20,750	

*Negligible quantity of natural gas estimated

Figure 6.5

(Gas Research Institute)

Table 8. Estimated coalbed methane resources, selected basins in conterminous United States.

PGC Region	Basin	PGC Province No.	State(s) included in evaluation	Estimated total methane in place (Tcf)	Estimated most likely recoverable resource, all resource categories (Tcf)
Eastern	Appalachian central*	P-120	KY, MD, TN, WV, VA	100 to 480 (1) 5 (2)	25 (2)
	Appalachian northern*	P-120	KY, MD, OH, PA, WV	61.0 (1)	
	Warrior (Black Warrior)*	P-150	AL, MS	5.0 to 100 (1) 19.8 (2) 39.0 (3)	8.0 (2) 15.0 (3)
	Illinois	P-220	IL, IN, KY	5.2 to 21.1 (1)	0.4 (4)
	Arkoma	P-410	AR, OK	1.6 to 3.6 (1)	(not estimated)
Western	Powder River	P-510	MT, WY	5.9 to 39.4 (1)	(not estimated)
	Wind River	P-520	WY	0.5 to 2.2 (1)	(not estimated)
	Greater Green River	P-530	CO, WY	0.2 to 30.9 (1)	(not estimated)
	Piceance*	P-540	CO	30.0 to 1100 (1) 83.9 (2)	29.7 (2)
	Uinta/Wasatch Plateau	P-540	CO, UT	0.2 to 0.8 (1)	(not estimated)
	Raton Mesa (Raton)	P-545	CO, NM	8.0 to 18.4 (1)	(not estimated)
	San Juan*	P-555	CO, NM	1.8 to 31.0 (1) 50 (Fruitland coals only) (2)	27 (2)
	Western Washington	P-600	WA	3.6 to 24.0 (1)	(not estimated)
TOTAL ESTIMATED METHANE IN PLACE FOR ASSESSED BASINS				133 to 448	
TOTAL ESTIMATED RECOVERABLE METHANE (most likely estimate) FOR ASSESSED BASINS ONLY					90.1 to 97.1

*Coalbed methane production known to be established

(1) DOE/METC (TRW)
(2) GRI/ICF Kaiser Energy
(3) University of Alabama
(4) Potential Gas Committee

Figure 6.6

(Gas Research Institute)

U.S. Tight Gas Sands Production

(1970-1987)

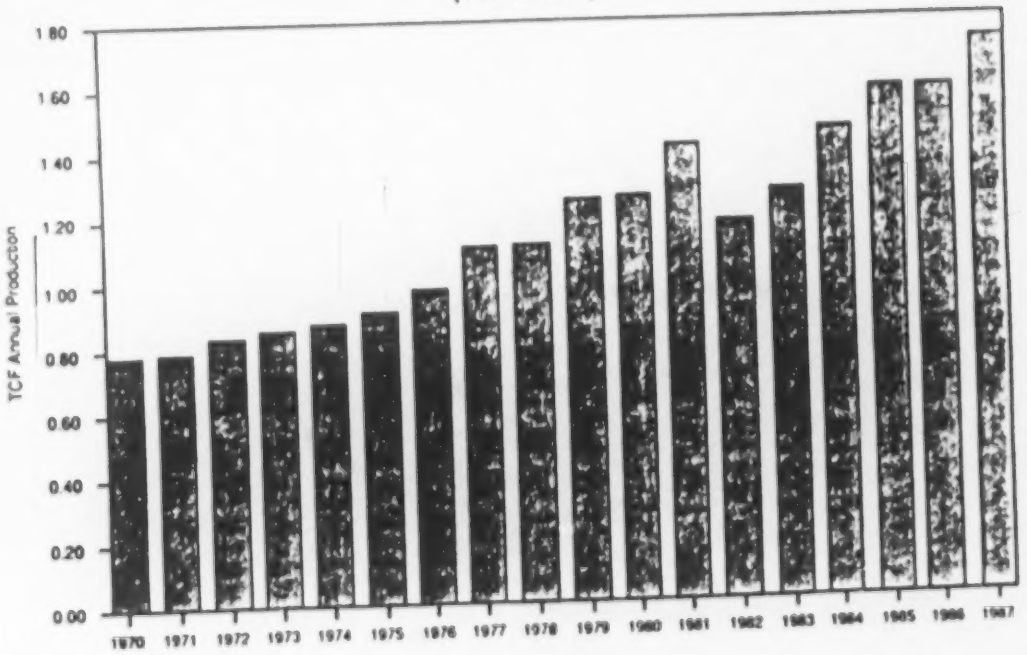


Figure 7.

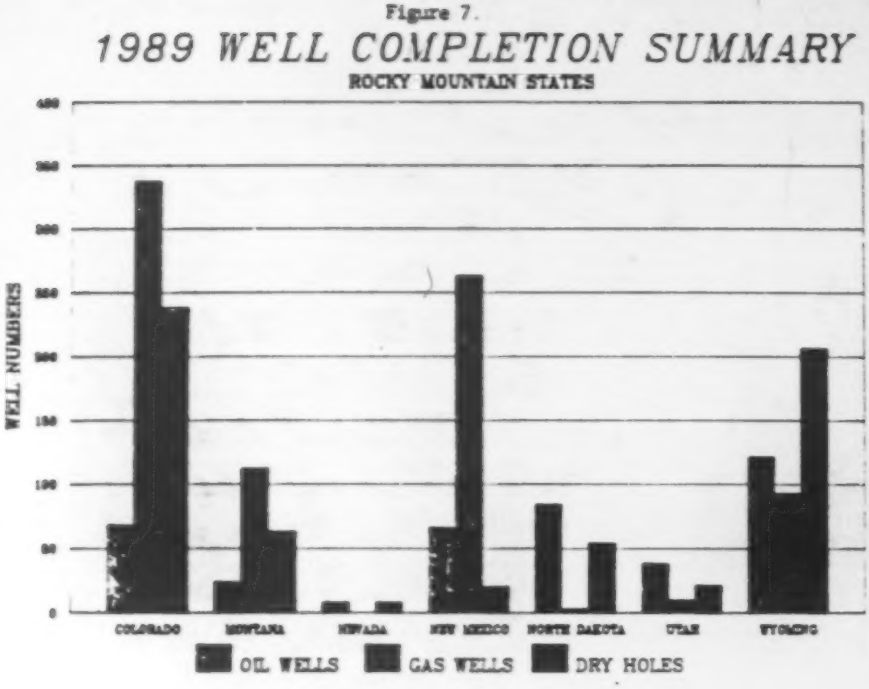

1989 WELL COMPLETION SUMMARY
ROCKY MOUNTAIN STATES
WELL NUMBERS
COLORADO
MONTANA
NEVADA
NEW MEXICO
NORTH DAKOTA
UTAH
WYOMING
OIL WELLS
GAS WELLS
DRY HOLES

Figure 8.

1989 WELL FOOTAGE SUMMARY

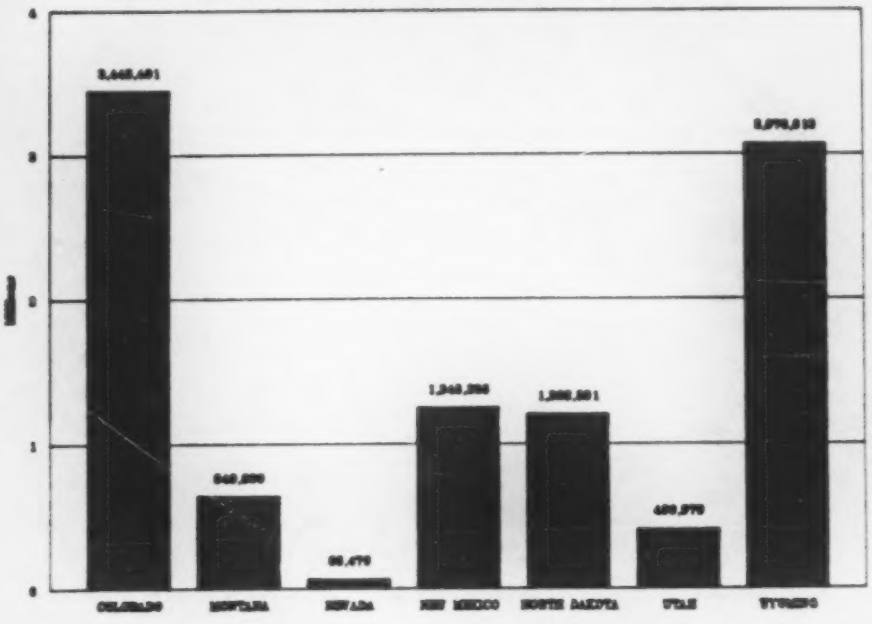
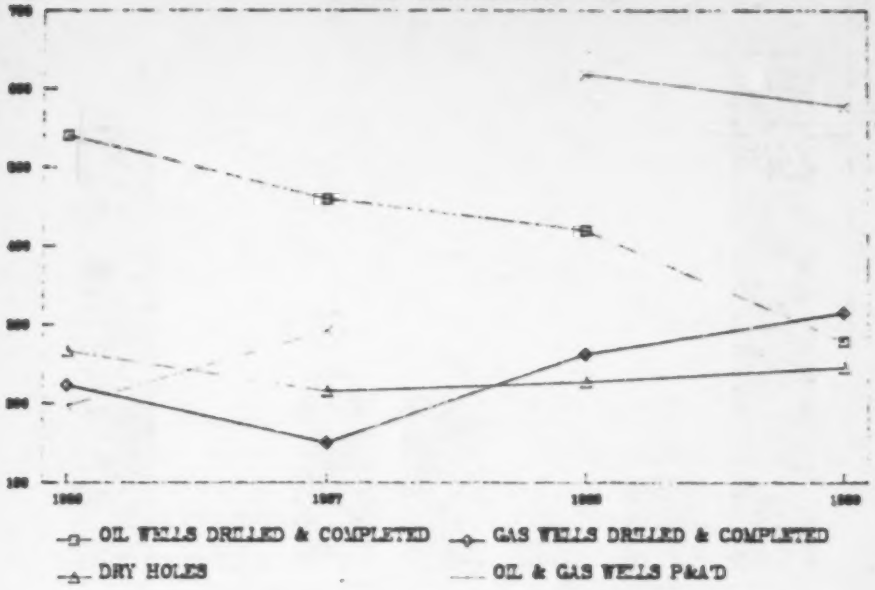


Figure 9.
(Colorado Oil & Gas Conservation Commission)

COLORADO DRILLING & COMPLETIONS

1986 THROUGH 1989



(Colorado Oil & Gas Conservation Commission)

Figure 10.

WESTERN SLOPE DRILLING & COMPLETIONS

1986 THROUGH 1989

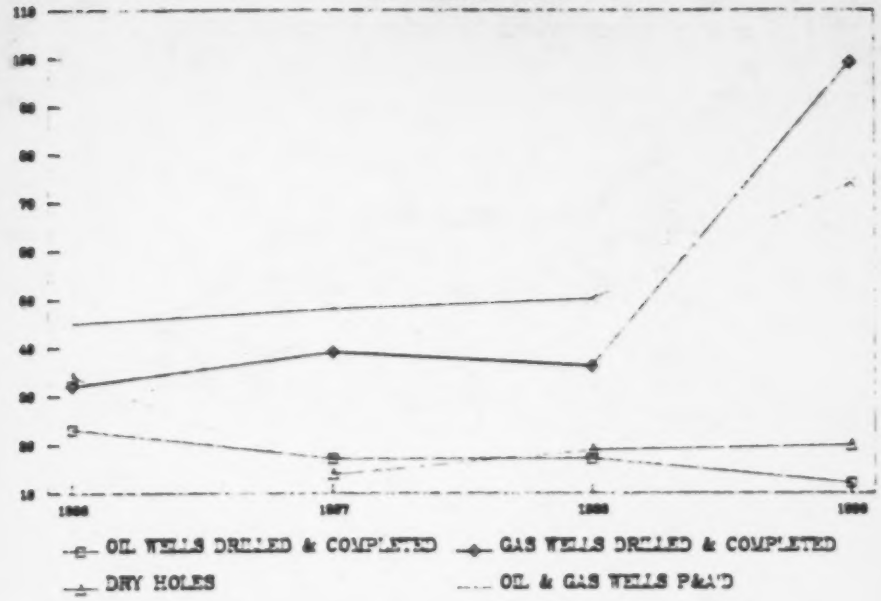
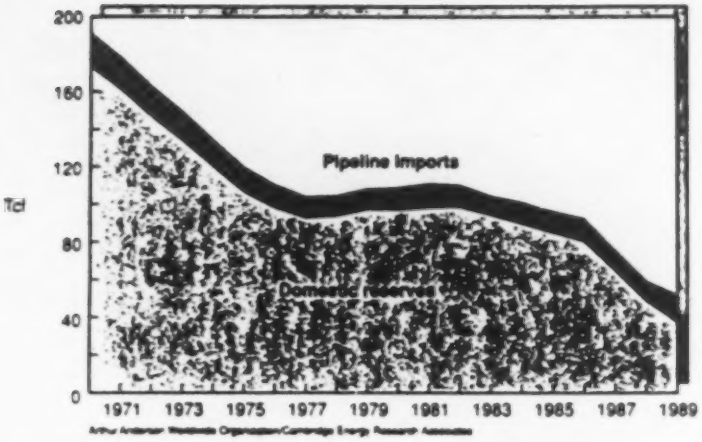


Figure 11.

Natural Gas Trends

Reserves Dedicated to Interstate Natural Gas Pipeline Companies

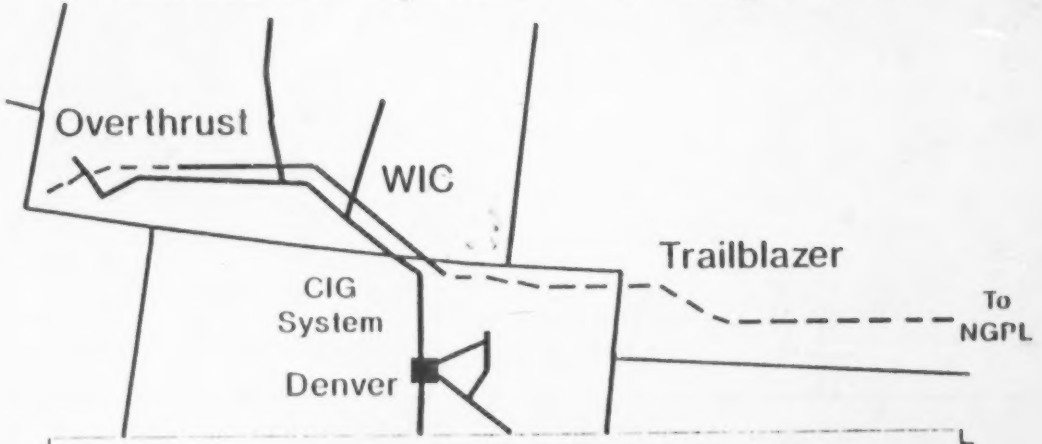


Production from reserves dedicated to interstate pipelines declined from 64% of total U.S. dry gas production in 1984 to 34% in 1989. Over the same period, total reserves dedicated to interstate pipelines declined by over 50% from 104.6 Tcf to 52.5 Tcf. These trends reflect the decline in the traditional gas merchant function of the interstate pipelines that has occurred over the last decade, as distribution companies have relied more heavily on spot purchases.

As transportation volumes have increased, sales of system supply gas from interstate pipelines have declined sharply. The reduction in use of the pipelines' traditional merchant function has forced many pipelines to release reserves previously committed to them under long-term contracts. Several pipelines have already implemented or proposed gas inventory charges (GICs) in order to pass through to their customers the costs of keeping remaining volumes of gas under contract so that they can cover the costs of "standing ready" to supply gas when called upon. As the structural changes accompanying the implementation of GICs evolve, more direct-sales transactions are being made under long-term contracts.

Figure 12.

Trailblazer System - 3 Segments



Capacity and Rates

	Overthrust	WIC	Trailblazer
Certificated Capacity (MMcf/d)	227	500	350
Settlement Rates ($/Mcf)	$0.104	$0.135	$0.305

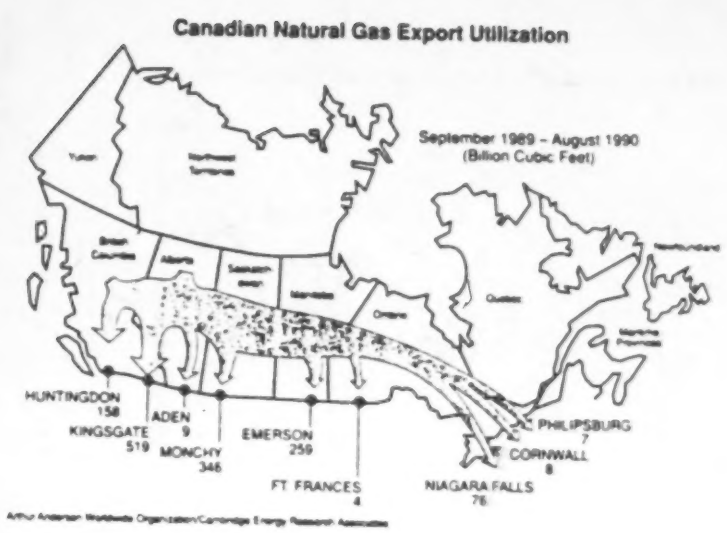
Figure 13.

Status

	Overthrust	WIC	Trailblazer	
Transport Status	Waiting Order	Settlement & Open Access Filed 2-6-90	Open (311)	
Rates ($/Mcf):				Total
Preopening	0.185	+ 0.299	+ 0.665	= $1.149
Open Access	0.104	+ 0.135	+ 0.305	= $0.544
% Reduction	-44%	-55%	-54%	-53%

Figure 14.

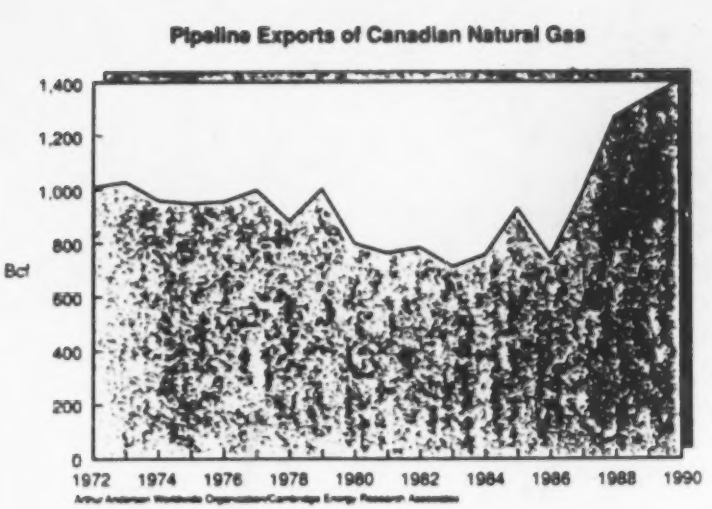
Natural Gas Trends



The 80% increase in Canadian natural gas exports since 1986 has been achieved principally through greater utilization of existing export facilities. With the exception of the Pacific Northwest, pipeline capacity at all major export points is nearly full during peak winter demand months. The major increase in exports and capacity utilization since 1986 has been through the pipeline systems serving the Upper Midwest through Monchy and Emerson. For volumes to California, capacity utilization through Kingsgate and the Pacific Gas Transmission system has exceeded 80% since 1986.

With most major export points near full capacity at peak periods, any incremental growth will come through greater exports during off-peak months, as well as through the construction of several new pipeline expansion projects. The majority of these are to the Northeast and include the TransCanada/Iroquois interconnection scheduled for full completion in 1992, as well as the various expansions associated with the Niagara Import Point Project, which are currently under construction. By 1992 export capacity to the Northeast could be as much as 1,000 million cubic feet (MMcf) per day greater. There will also be an expansion of the Great Lakes system through Emerson, principally to serve the Northeast markets, as well as a 150 MMcf per day expansion of the Northern Border pipeline at Monchy, scheduled for completion in late 1991.

Figure 15.

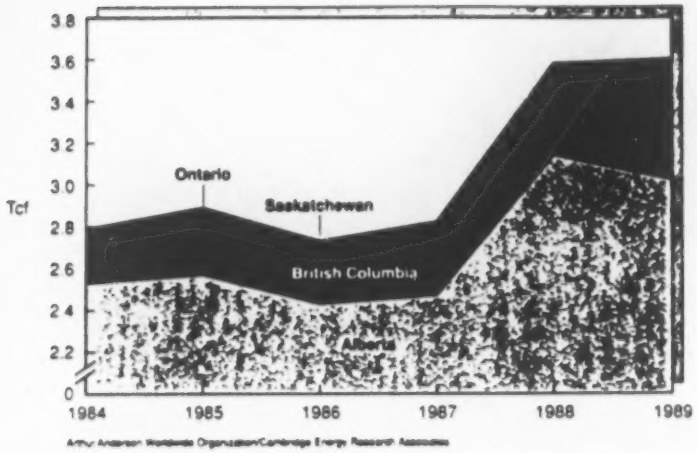


Canadian gas pipeline exports in 1989 continued their strong rebound since falling to 749 Bcf in 1986. Gas exports rose to 1,337 Bcf in 1989 and should reach 1,400 Bcf in 1990. Canadian gas exports have been one of the principal incremental supplies for meeting the 2 Tcf increase in U.S. gas demand over the same period. The major growth in exports has been to the Upper Midwest, where greater use of the existing Northern Border, Viking, and Great Lakes pipeline systems has allowed a 300 Bcf increase in annual exports to that region since 1987. Strong growth has also been made to the Northeast where exports have more than doubled to an estimated 130 Bcf for 1990. Gas flows west have only modestly increased since 1987, reflecting capacity constraints into the California market, and a relatively weak gas market in the Pacific Northwest.

The average export price for Canadian gas remains below $2.00 per MMBtu, reflecting the continuing effects of price deregulation and the more integrated North American gas market. Weak netback values, particularly from the Midwest, should lower the average netback price in 1990, although the existence of some contracts with escalation terms tied to oil prices should lessen the downturn.

Figure 16.

Canadian Natural Gas Production



Proved natural gas reserves in Canada grew by over 2 Tcf in 1989 to 97.0 Tcf. Aggregate reserve replacement was a strong 162%, with all the major producing regions showing gains. This strong reserve replacement ratio was realized despite weak prices and a surplus of Canadian gas reserves and production capacity. Still, the reserves-to-production ratio has declined from 36 in 1986 to 27 in 1989, principally reflecting higher exports and thus production levels.

The Canadian reserve numbers include 25.4 Tcf of essentially non-producing frontier gas. Exempting these reserves lowers the Canadian reserves level to 71.6 Tcf, but still leaves a healthy 20-to-1 reserves to production ratio.

The geographic distribution of reserves and production in Canada remains concentrated in Alberta, which accounts for 62% of total reserves and 83% of production. British Columbia, which accounts for 8% of the reserves, has increased its share of production from 9% in 1986 to 11% in 1989. The remaining 6% of production comes principally from Saskatchewan.

Western Gas
Marketing
Limited

530 Eighth Avenue S.W.
P.O. Box 900, Station M
Calgary, Alberta
T2P 2V8
(403) 269-6011

EXHIBIT 16.1

1989-06-16

Petrodyne Ltd.
Attention: M. Haywood
6501 North Broadway
Oklahoma City, Oklahoma
73116

Dear Sirs:

Under Article III of your long term netback agreement, Western Gas has agreed to consult annually with you in order to outline its strategies and plans. For 1989, this process was initiated in a meeting with producers on May 24, 1989.

The purpose of this letter is to provide you with a more thorough statement of Western Gas' present marketing strategy and to afford the opportunity for you to review and comment on that strategy.

To a large extent, this procedure of annual consultation formalizes a process undertaken with producers in August of 1988 as a preliminary to negotiations with eastern Canadian distributors. At that time, Western Gas reviewed with its producers its understanding of the nature of changes occurring in the gas industry and the role that Western Gas expects to take on behalf of its producers. Western Gas also reviewed the status of its negotiations for supply arrangements with eastern Canadian distributors, identified key issues and described the solutions that Western Gas proposed to implement.

Western Gas received responses from approximately 150 producers. These responses were of great assistance to Western Gas in finalizing the subsequent distributor negotiations. Without this serious producer response, the recently concluded eastern distributor arrangements may not have been achieved. With this letter, Western Gas seeks to continue discussions with producers and encourages producers to give the following review the same serious consideration and response.

Exhibit IPA- 18 ram- 4

In the August, 1988 letter, Western Gas dealt with specific contractual and structural issues that related to a possible restructuring of the Canadian market. This letter takes a broader approach. On the assumption that it is timely to attempt to frame a more complete context for the marketing of Alberta gas, the following discussion attempts to set out a basis for a continental marketing strategy. The first section addresses each of the four market areas that Western Gas believes to be critical. The second section discusses generally the approach that Western Gas considers must be taken by the Alberta industry if it is to benefit fully from the fact of deregulation. The third section continues the explanation of Western Gas' role in the purchase and sale of Alberta gas and the fourth section sets out a summary of the strategy that Western Gas intends to pursue.

SECTION I: FOUR STRATEGIC MARKET AREAS

There are four market areas that are fundamental to developing a continental strategy for marketing Alberta natural gas. These are the Midwest, the Northeast, California, and Eastern Canada.

THE MIDWEST is a traditional market for Alberta supply. Since 1960, Alberta has sold significant gas volumes off the TransCanada system into the Midwest through the Emerson export point and, more recently, through Monchy, Saskatchewan, on the Foothills/Northern Border system. All major supply areas on the continent are well connected to the Midwest through major pipelines and therefore, in a deregulated context, the Midwest is an intensely competitive market area.

THE NORTHEAST is an area of significant incremental market demand. Its traditional supply source, to which it is connected by several interstate pipelines, is the U.S. Gulf Coast area. The Gulf Coast reserves appear to be in decline and there is growing regional competition for this supply. Also, market demand is growing rapidly. The Northeast therefore has an immediate need to attach supply sources in other production areas. To accommodate this need, substantial facilities construction will be required.

THE CALIFORNIA market, for which incremental demand is forecast, has historically taken a large portion of its gas from Alberta sources. This market has yielded Alberta producers favourable prices and load factors, and, as a result, there is great interest in building new pipelines into California to deliver additional volumes of Alberta gas.

Over the last three and one half years, the deregulation of the markets of EASTERN CANADA has been largely achieved. The recent long term supply contracts between Eastern Canadian distributors and Western Gas seem to have resolved the major structural issues and Eastern Canada is settling into being a long run competitive market. These contracts accommodate direct sale displacements and this fact, together with availability of transportation on the TransCanada system, accelerating production out of Saskatchewan,

and renewed imports of U.S. gas through Union Gas, means that competition in this market area will be particularly intense.

What follows is a more detailed discussion of each of these critical market areas.

THE MIDWEST

An understanding of the history and dynamics of the Midwest supply/market configuration is key to the development of a broader continental strategy.

The Midwest market is the major heavy industrial area of the United States and much of the U.S. gas industry has evolved to satisfy the very large volume requirements of the Midwest industrial complex. The U.S. mid-continent reserve areas (the Anadarko basin area of Kansas, Oklahoma and the Texas Panhandle and the Permian basin area of West Texas and New Mexico) have developed in parallel with the four major U.S. interstate pipelines (Northern Natural, Natural Gas Pipeline, ANR, and Panhandle) that deliver into the Midwest areas. Also, the Midwest is connected to the U.S. Gulf Coast reserve area through other pipeline systems (Trunkline, Natural Gas Pipeline, ANR and the Midwestern southern system). Since 1960, the Midwest has had access to Alberta supplies at the Emerson export point through the Midwestern northern system and later through Great Lakes Gas Transmission.

With this highly developed supply and transportation infra-structure, the Midwest markets were consuming, in the early 70's, approximately 4.7 Tcf per year. During the period of oil price shocks in the late 70's and early 80's, consumption fell off somewhat for price related reasons. However, fear of gas shortages during this period induced the connection of new supplies through new transportation systems. In 1980, the Trailblazer pipeline directly connected the Midwest to new reserves in the Rocky Mountain basin of Wyoming. In addition, the Foothills/Northern Border construction of 1982 further increased the availability of Alberta supply in the Midwest.

With the completion of these new facilities, the supply/transportation resource for Midwest markets reached a peak level. At almost the same time, Midwest industries were subjected to the recessionary conditions of the early 80's and underwent significant restructuring. The annual consumption level in the Midwest declined from the 4.7 Tcf level of the early 70's to present levels in the 3.3 to 3.6 Tcf range. These declines are almost entirely related to the loss of industrial loads.

For these reasons, the supply/transportation resource built for and dedicated to the Midwest markets significantly exceeds that market's annual requirements. Though it is generally conceded that the Gulf Coast reserves, which the Midwest has historically shared with the Northeast, are in decline, the Mid-continent reserve area, to which the Midwest has almost

exclusive access, exhibits significant potential for new reserve development. Though existing deliverability from this area is in delicate balance with market requirements (at an R/P of approximately 10 on approximately 30 Tcf of proven reserves), the Potential Gas Committee (1986 Report) identifies, in addition to proven connected reserves, a potential reserve increment of 200 Tcf, consisting of "probable" reserves of 48 Tcf, "possible" reserves of 90 Tcf and "speculative" reserves of 62 Tcf. The possibility of major incremental supply development in the Mid-continent is therefore very significant. Also, the Rocky Mountain reserves, which are in an early stage of development have approximately 15 Tcf of proven reserves. The Potential Gas Committee identifies a potential reserve increment of approximately 114 Tcf for this area, consisting of "probable" reserves of 36 Tcf, "possible" reserves of 53 Tcf and "speculative" reserves of 25 Tcf.

Given the reserve potential, the decline in traditional markets and the excess capacity of the major pipeline systems, Western Gas believes that the U.S. mid-continent and Rocky Mountain reserve areas have a long run capability not only to support Midwest markets, but also to compete for incremental demand in non-traditional market areas to which they are not now significantly connected.

Facilities for delivering Alberta gas into the Midwest were first constructed off the TransCanada system through the Emerson, Manitoba export point. These facilities were supported by TransCanada's sales contracts with Northern Natural, ANR, Natural Gas Pipeline, Midwestern, and Great Lakes Gas Transmission which, in aggregate, involved firm delivery commitments of approximately 600 MMcf per day or 220 Bcf per year. Sales commitments made to Northern Natural in the early 80's (by TransCanada and Progas) for delivery onto the Northern Border system at Monchy added another 50 Bcf per year to the Alberta-Midwest commitment.

These commitments of Canadian gas supply were made in the expectation that the gas would be taken and, prior to the supply/demand problems that emerged in the early 80's, gas was taken at the expected levels.

With restructuring of heavy industry in the Midwest and the general decline in gas requirements in that area, pipelines in the Midwest that had responded to the gas shortage scare by undertaking major new purchasing commitments began to incur serious take or pay obligations with U.S. producers. The pipelines' position on take or pay incurrment was seriously impaired in 1983 when FERC Order 380 prohibited the rate inclusion of minimum bills that assured the recovery of take or pay related costs. The situation worsened in 1985 with the introduction of the open access transportation regime under FERC Order 436. Direct sale displacements resulting from open access transportation were accelerated because system gas prices, derived in part from high pricing levels of deregulated supply obligations, were higher than the market clearing price of direct sale volumes. This process caused the pipelines to experience enormous additional market losses. The annual sales volumes of Natural Gas Pipeline, for example, declined from a historical level of about 1 Tcf to 200 Bcf in 1987. In effect, the Midwest interstates had

Exhibit IPA- 18 ran- 4

become peaking services for Midwest customers. Sales volumes under the Alberta-Midwest supply contracts were drastically reduced. During the 1986/87 contract year, for example, Natural Gas Pipeline purchased only 3.9 Bcf out of a possible 63 Bcf from TransCanada. In the same contract year, ANR purchased 12.7 Bcf out of a possible 124 Bcf.

With the implementation of deregulation in the U.S., Western Gas recognized the inability of the interstates to continue to be reliable purchasers of gas and adopted a strategy to market gas directly to Midwest LDC's. Implementation of this strategy was hampered with the introduction by Northern Natural, Natural Gas Pipeline and ANR of defensive market zone tariffs that loaded system costs onto Canadian gas moving from the north. This forced Western Gas to negotiate supply contracts in support of LDC proposals to bypass the interstates. The most significant example of this approach is the Minnegasco sale, which commenced deliveries in December of 1988.

The circumstances of deregulation placed interstate pipelines under intense pressure to restructure their gas purchase obligations. Constant negotiations by interstates with U.S. producers have led to settlement of take or pay disputes and reformation of pricing provisions to reflect competitive market realities. Significant quantities of gas have been released and mechanisms have been developed by the FERC to provide an opportunity to recover take or pay settlement costs. Though this has been an arduous process, some of the pipelines have been reasonably successful in establishing supply relationships in a market responsive mode.

Notwithstanding the erosion of their traditional merchant function, pipelines have never ceased to operate under the constraint of being the ultimate supply source within their delivery areas. This constraint has induced rate structure proposals intended to recreate a significant level of market security for the pipelines so that they can, in turn, attract a secure supporting gas supply to meet market obligations. The current initiative, which is considered to be of great importance by the FERC, involves the implementation of gas inventory charges (or "GIC's") which are basically minimum commodity bills. The recent Northern Natural restructuring proposal is a particularly aggressive example of this trend. This proposal, if implemented, almost entirely precludes the possibility of further by-passes of the Northern Natural system and, through a combination of an increased market zone tariff and stand-by commodity charges, makes direct sales to Northern's customers difficult for U.S. producers and practically impossible for Canadian producers.

Western Gas is opposing a number of these restructuring proposals on the argument that they effectively eliminate a competitive market in the interstates' delivery areas.

The basic point, however, is that, notwithstanding the primary thrust of deregulation in the U.S. to create freely competitive gas markets, there is a countervailing trend, grounded in the consumers' ultimate need for supply security, that seeks to resecure the gas purchase/merchant functions of the interstate pipelines, albeit on a more limited scale than

before. This means that, following a period in which the interstates were minimal purchasers of Canadian gas and poor customers within the context of the historical contracts, the Midwest interstates are likely to re-establish themselves, to some degree, as reliable markets for Canadian gas.

At the same time, Western Gas expects that the Midwest LDC's, seeking diverse supply portfolios and direct long term supply access, will also be desirable customers.

The regulatory process is not resolved on these issues and it cannot yet be clearly determined whether or to what extent gas supplies will be purchased for the Midwest market by interstates or LDC's (or end-users).

The situation for Canadian gas sales to the Midwest is nonetheless at a critical point because each of the Midwest export contracts expires at various times over the next three years. Western Gas is actively involved in negotiations to extend these arrangements within the new industry structure.

It is important to appreciate that the Midwest market is, at best, a zero sum game for Alberta producers. Because of the flat diminished market and the many alternative transportation and supply resources available to the Midwest, only a certain volume of Alberta gas can be sold in the Midwest over the near term and the volumes that are sold will be generally priced within highly competitive market conditions.

THE NORTHEAST

The primary feature of the Northeast gas market is that there is a significant demand for additional gas supply. This requirement for new supply proceeds from several factors.

First, the U.S. Northeast market has traditionally obtained gas supplies from the Gulf Coast area through three major interstate pipelines (Tennessee, Transco and Texo). New supplies have been recently available from Canada (Tennessee and Boundary Gas at the Niagara Falls export point), but apart from these purchases and some limited local quantities, the Northeast is not significantly connected to other supply areas. The problem with this circumstance is that the Gulf Coast reserves are in decline and, to the extent that gas is available from those reserves, the Gulf Coast industrial markets and growing southeast U.S. markets are aggressively competing for the supply available. In addition, to the extent more supply could be available from the south (by reducing Gulf Coast deliveries in the Midwest, for example), the three existing interstate pipelines have insufficient capacity to meet demand and the expense of expanding their systems would be very substantial.

The second important factor about the Northeast is that it is a growing market for gas. From 1975 to 1987, gas usage in the Northeast increased by 34% despite a general decline in gas usage in the U.S. This increase in usage is related to economic and population growth in the area and, more recently, to a very significant increase in demand for new electrical generating capacity, driven in part by the present weakness of the nuclear power industry. There is also a new demand emerging for natural gas in the Northeast that is based on environmental issues. The primary constraint on market growth in the Northeast is not an absence of demand for gas, but an absence of long term gas supplies and adequate pipeline capacity.

The two most likely potential sources of incremental gas supplies to the Northeast are the U.S. Mid-continent/Rocky Mountain reserve basins and the Western Canadian sedimentary basin. In either case, significant new transmission facilities are required in order for either of these reserve areas to provide the Northeast with new supplies. In 1979, a group of major Northeast LDC's undertook a joint study to determine ways of diversifying their gas supplies. In 1980, 14 of these LDC's organized the Boundary Gas project with the object of obtaining new supplies from Canadian sources. Through the market aggregating vehicle of Boundary Gas Inc., these LDC's contracted with TransCanada for gas deliveries at Niagara Falls, Ontario, and arranged with Tennessee to move volumes to their distribution systems from Niagara Falls. After several years of regulatory proceedings, Phase I of the Boundary arrangement commenced deliveries on November 1, 1984, at a level of 40 MMcf per day. In 1988, Phase II of the Boundary project commenced delivery of an additional 52.5 MMcf per day. It was the original intention of the parties that a third phase of the Boundary project would be implemented at 300 MMcf per day. This third phase has since been transformed into the sale by Western Gas to Alberta Northeast Gas Ltd. ("ANE") that is currently proposed, along with other Northeast supply arrangements, for delivery through the Iroquois pipeline.

At this time, Alberta gas supplies have a distinct advantage over the U.S. Mid-continent supplies in attaching Northeast markets. The large quantity of proven Alberta reserves is capable of under-pinning the financing of the required new facilities construction. On the other hand, the Mid-continent reserves, though exhibiting considerable potential for new supply development, function at minimal levels of deliverability to serve existing markets and, as matters now stand, will not easily serve to support major facilities construction. The long term supply position of the Alberta industry and its ability to enter into long term firm supply contracts also contrasts with what is currently available from the Mid-continent. The backfeeding of Northeast distribution systems from the north is regarded as the most cost efficient way of adding the required new facilities. It allows the LDC's to avoid the greater expense of incrementing existing systems which telescope down in a south to north direction. For these reasons, the major Northeast gas buyers have made extended efforts and significant commitments to purchase long term gas from Alberta.

In recent months, there has been an intense debate in the Canadian gas industry on the question of whether Canadian gas should serve a larger portion of the Northeast market. This debate has particularly concerned itself with the cost of the incremental facilities required to increase deliveries to that market. The cost of facilities is important insofar as it will be a factor in determining the prices that producers will receive for the gas sales, but this importance notwithstanding, it is essential that the strategic consequences of either attaching or not attaching the Northeast market be carefully considered. In particular, producers should address the following:

- The Northeast market is the only major U.S. market that has made a strong commitment to purchase Canadian volumes. This commitment has been made not only by the LDC customers, but, if the expedited result of the Northeast "open season" proceedings at FERC is an indication, by the regulators as well. Considering the intensely competitive nature of the U.S. producing industry, the arduous process of competing to displace U.S. production in traditional markets and the usual slow complexity of U.S. regulatory procedures, this commitment must be highly valued.

- If Canadian producers fail to supply gas to the Northeast market to meet this very real incremental demand for gas, there will result a powerful vacuum in the Northeast and facilities will be constructed, perhaps in piecemeal fashion, to bring Mid-continent supplies to the Northeast. The prospect that U.S. Mid-continent producers might access a major incremental market in the Northeast can be expected to stimulate exploration and development in these dormant U.S. production areas. If Canadian-sourced facilities are not built at this time and a U.S. delivery solution evolves, the opportunity for Alberta producers to gain their own access route to a major incremental market will be lost for the foreseeable future and, perhaps, permanently.

- Because of the importance that new facilities to the Northeast back-feed existing systems, the most logical pipeline route for U.S. gas supplies to reach the Northeast is through existing midwest interstate pipelines that reach into Michigan and the Michigan storage fields, through the Ontario facilities of Union Gas, into New York State through Niagara Falls and down into the New York City/Long Island area. If such facilities were constructed on a major scale, they would not only supply significant volumes to the Northeast market, thereby locking out a direct Canadian pipeline link, but would also establish major new facilities for delivering U.S. Mid-continent and Rocky Mountain gas into Ontario. A failure by Alberta producers to pursue and complete the attachment of the Northeast markets will therefore have the effect of further undercutting the sale of Alberta gas in its traditional Canadian market area.

- Currently, there are proposals to build facilities to move Mid-continent gas from the Midwest through the Union Gas system and into upstate New York. As matters stand, these proposals are relatively modest in scope (involving, initial capability in the range of 150 MMcf per day). The intention is that certain long term Canadian supplies be involved in this project and be delivered through the Great Lakes Gas Transmission system into the Michigan area for streaming to New York with U.S. supplies. The object of including long term Canadian gas in these arrangements is presumably to under-pin the financing of facilities construction. If the current proposals to connect Canadian supplies directly to the Northeast fail, this alternate proposal is well positioned to expand into major Northeast population ar . This project proposes to increment facilities construction into the Northeast on the security of Alberta gas supply and thereby open Northeast markets to new U.S. gas supply that could not otherwise support facilities construction. Western Gas believes that, from the point of view of Alberta producers, such an approach to the development of new delivery systems, in which U.S. supplies are piggy-backed to market on the security of Alberta supplies, is a much inferior approach to developing incremental markets for Alberta gas.

- The loss by Alberta producers of the Northeast market opportunity, and the resulting consequence of a deterioration in Canadian market sales, will increase the supply excess in Alberta and will tend to force the Alberta supply into the western part of the continent, leaving Alberta producers to attempt the recovery of significant volume losses by competing to obtain new market share in a flat and intensely competitive Midwest market and by attaching whatever new market volumes may be available as California opens up over the next five to seven years.

- If a direct Canadian link to the Northeast is built, it will have the effect of absorbing over one-half Bcf per day of excess Alberta deliverability. Incremental sales at these volume levels will significantly restore the supply/demand balance between Alberta and its markets and will clearly have an ameliorating effect on gas prices.

- At the same time, establishing major delivery systems for Canadian gas into the Northeast will reduce the likelihood that major new delivery systems for bringing Mid-continent supplies to the Northeast and Southern Ontario will be constructed.

- Fundamentally, the Northeast issue is balanced on the question of whether Alberta producers will take advantage of their current opportunity in the Northeast, which, by drawing down the supply excess, will result in a major economic stimulus to the Alberta industry or whether they will concede that market to U.S. producers and encourage a major stimulus for the Mid-continent producing areas. Simply put, the question is whether U.S. production areas will be afforded significant development opportunities at the expense of the Alberta industry.

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CALIFORNIA

Through Alberta and Southern sales, California has provided an attractive market to producers over the years and, historically, Alberta producers have supplied about 22% of California's annual gas requirements. The California market has offered the attraction of solid commodity prices, low transportation costs and high load factors.

Events in California suggest that, during the next number of years, there will be incremental requirement for gas supply in California. This fact, together with the experience of attractive load factors and netbacks, has created great interest among Alberta producers in marketing incremental gas volumes to California through new facilities.

While Western Gas foresees considerable potential in California as an incremental market for Alberta gas, it believes that, the benefits of previous sales notwithstanding, the circumstances under which new Alberta volumes would be sold into California will be quite different than before and the potential of this market should not be over-estimated. It is particularly important that California not be regarded as so attractive that other market possibilities are excluded from consideration. The following should be considered:

- Unlike the Northeast market area, there is no clear commitment from buyers in California to purchase major incremental volumes of Canadian gas or to pick up the fixed transportation costs that would be required to access their market areas.

- The high netbacks from the Alberta and Southern sales have resulted, in part, because the gas is marketed within a closed system. That is, gas purchased by Alberta and Southern is subsequently sold to PG&E, its parent company, and PG&E resells the gas within its controlled market area. As well, attractive netbacks have resulted from the low transportation costs of the PGT system, which is a fully depreciated pipeline.

- By contrast, the construction of new pipelines into California, will, as now proposed, involve incremental transportation costs on new systems. The increased pipeline capacity will exceed near-term growth and therefore gas to gas competition in California and generally reduce commodity prices. The combination of reduced commodity prices and increased transportation costs will result in substantially lower netbacks to Alberta producers than they now receive from California sales.

- The California market is also attractive to U.S. producers, who have significant under-utilized and undeveloped volumes in the nearby Rocky Mountain reserve areas which currently supply only 1% of California's gas requirements. In addition, the Mid-continent is likely to be stimulated to additional development by any increase of pipeline capacity into California. The development of new supply for California will necessarily include new supply from these U.S. production areas.

- At this time, there are five pipeline proposals for delivery of gas from both U.S. and Canadian sources into California. Which of these various pipelines will be constructed is by no means clear and it is unlikely that gas will actually flow for at least five years.

EASTERN CANADA

Western Gas has recently completed major supply contracts with the Eastern Canadian distributors. The volume obligation under these contracts is approximately 60% long term (12 - 15 years) and 40% shorter term (3 - 5 years). Western Gas sells additional supplies to these markets through interruptible, short term and winter peaking arrangements. Prior to deregulation, the Western Gas supply pool supplied upwards of 100% of these markets. Presently, the Western Gas share has been reduced to approximately 70% of Eastern Canada's supply needs. The reduction has occurred as the market opened and as alternative supplies from Alberta, Saskatchewan and the U.S. have become available.

In keeping with the purpose of deregulation, the new Western Gas/distributor contracts were negotiated to accommodate gas to gas competition by allowing distributors to reduce obligation to account for direct sale displacements. This means that, in order to retain sales volumes to Canadian distributors at or near originally agreed upon obligation levels, Western Gas must compete effectively with other suppliers to Eastern Canada.

In the industrial markets of Eastern Canada, Western Gas competes by offering the LDCs' industrial customers discounting arrangements under the System Gas Resale ("SGR") program and by making direct sales. All of the SGR and direct sale arrangements are of two years duration or less and are continually coming up for renegotiation and renewal. To retain this market, Western Gas must match short term market prices that are determined in competition among numerous potential suppliers. It also means that, as supply tightens, there is contractual flexibility to capture the benefits of increasing price pressure.

A number of producers have indicated that they wish to send price signals to the market by voting on each of the large industrial sales contracts. While this is possible within the terms of the Alberta Natural Gas Marketing legislation, it is not a practical approach for the following reasons:

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- A number of the Western Gas producers are also competitors in the Ontario market and revealing the precise details of individual industrial arrangements puts Western Gas at a distinct disadvantage by telling competitors exactly what Western Gas is doing in the industrial sector.

- It is not a reasonable marketing practice to disclose publicly the precise terms of a short term deal with a customer. Though price disclosure may be appropriate for a regulated utility, it would not be acceptable practice from the point of view of the individual industrial customer whose business decisions are not generally subject to such public scrutiny.

- Negotiation of arrangements with industrial customers is severely hampered if the outcome of those negotiations must be subject to the condition that producer support be obtained under a process that may take an additional three weeks before the arrangement is confirmed.

- The overall effect of these difficulties would be to limit Western Gas' marketing flexibility and put the Western Gas supply at a discount in the industrial market rather than at a premium.

At this time, Western Gas has approximately 100 Bcf per year of large volume (5 Bcf or greater) industrial market contracts up for renegotiation before the end of 1989. It would be extremely ill-advised to put such a large market at risk by attempting to send a message to the market by offering producers the opportunity to vote on these deals individually.

Western Gas has recent experience with the consequence that could be expected. Currently, we supply about one-half of the total annual requirements of an industrial customer that consumes 12 Bcf of gas per year. In order to renew the arrangement for the coming year, Western Gas bid higher than last year and offered, at the same time, to provide certain non-price related services. As a result, the sale was lost to competitors who offered lower prices. The only signal that Western Gas has sent to the market in this instance is that it was not prepared to compete with supply alternatives.

There is no substitute for competing and maintaining a strong presence in the market place. If Western Gas is not prepared to meet competitors' prices there will be significant volume losses. Retention of Ontario industrial volumes is particularly important over the next two or three years because, during that time, there will be very little increase in pipeline capacity to export markets.

SECTION II: GENERAL

The following observations are more general.

The impetus to deregulation in Canada came primarily from the Alberta producing community and the Alberta government who sought to open new markets in the U.S. for Alberta's excess supply. In its quest for U.S. markets, Alberta and its producers have proceeded on the assumption that, with Alberta's strong reserve position and the decline in U.S. domestic supplies, a continental market would allow the attachment of m. .. new U.S. markets and Alberta producers would be in a position to market much larger volumes than before. This would create major economic growth in Alberta.

This is an appealing conclusion, but it is perilous to assume that the outcome is inevitable. Prior to 1986, Alberta producers could identify certain domestic gas markets upon which they could rely because their gas was marketed within a regulated market system. The price paid by Alberta producers for the opportunity to compete more freely on a continental basis was the loss of this secure market position. Any markets previously taken for granted are now retained or lost within the competitive process. There are conspicuous examples of this point:

- Before deregulation, Ontario customers did not buy gas produced in Saskatchewan. Western Gas estimates that between 300 and 400 MMcf per day of Saskatchewan gas is now being sold into Ontario. Through the process of deregulation, this Saskatchewan gas has displaced Alberta producers in their traditional market. This displacement can be expected to increase.

- There is a renewed presence of U.S. gas in Eastern Canadian markets. So long as U.S. production can compete successfully, imported volumes will continue and can be expected to increase. The new environment that yields opportunities for Alberta gas to move south also offers opportunities for U.S. gas to move north.

While an open continental gas market offers important new marketing opportunities for Alberta gas, it also offers opportunities for other suppliers to displace Alberta producers in traditional markets. It is perhaps too early to determine whether Alberta will be a net winner or a net loser, but it is important to emphasize that either possibility could occur and nothing should be taken for granted.

Western Gas believes that if Alberta producers and the Province of Alberta are to obtain the maximum benefit from the uncertain and complex process of deregulation, producers must

adopt a realistic continental strategy and a thoroughly competitive approach in the marketing of Alberta gas. In this respect, Western Gas believes the following to be fundamental:

- Alberta producers must compete to retain their market share in traditional markets. Wherever a unit of traditional market is lost, there must be a unit of new market found simply to avoid a net loss. This means that Alberta producers must be prepared to compete vigorously in all Eastern Canadian markets and in the U.S. Midwest. The attachment of new markets loses significance if traditional markets are lost at the same time.

- Each U.S. market area has, as part of its annual requirement, certain supply needs that Canadian gas is well positioned to satisfy. For example, Midwest interstates or LDC's prefer to include some long term supply commitment within their portfolios of gas supply or recognize an operational need to supply their systems from the north. For either case, Alberta gas has an advantage over U.S. supply alternatives and the objective of the Alberta industry should therefore be to seek to attach that part of any U.S. market which requires these particular supply characteristics. Attachment by Canadian producers of that portion of any market that is not particularly predisposed to Canadian gas may also be achieved, but with greater difficulty and only after the most intense competition with U.S. producers. This is a primary argument against undue concentration on any one market area to the exclusion of other market areas.

- The marketing of Alberta gas must be regarded as a cumulative process. Alberta must first retain and maintain its historical markets and, from that base, compete vigorously to attach new markets in whatever areas of the continent may be reasonably served from Alberta. A successful approach to market accumulation requires the understanding and acceptance of different competitive circumstances prevailing within diverse market areas. It also requires (because Alberta is pipeline constricted) that Alberta producers support the construction of facilities into new market areas. It is fundamental that the Alberta industry not regard one market area as expendable upon the attachment of another market area. That is, the Midwest cannot be sacrificed in favour of the Northeast or the Northeast sacrificed in favour of California. Western Gas believes that such an approach can only result in a net loss situation.

- In the process of evaluating markets, Alberta producers should not be narrowly critical of the particularities of various markets. Present market characteristics, such as the competitive intensity of the Midwest, will evolve and change as new transportation systems are built and the continental supply/demand balance is rationalized.

- The cumulative approach to developing continental markets for Alberta supply also recognizes that market opportunities can be expected to mature at different times. At present, Western Gas producers must be concerned to maintain existing Canadian and Midwest markets. They must also address and resolve the issues of new supply commitments to Northeast U.S. markets. Opportunities in California, however, have not yet been fully defined and final commitments to that market area will not likely be made for some time.

- Western Gas believes that producers do not have the option of taking an overly-selective approach to market attachment. A decision to decline present market opportunities on the prospect of future market opportunities increases the risk of a net loss position for the Alberta industry, whether the future market opportunity materializes or not.

- By maintaining a cumulative approach to market attachment, Alberta producers will maximize market presence for Alberta supplies and, over the long run, maximize the market share of Alberta producers. The failure to compete for market share and establish market presence, because of an over-particular concern with individual market characteristics or present factors in those markets, increases the opportunity for other continental production areas to establish market presence and concedes to these production areas the increasing benefits of the additional market share as supplies tighten.

- There is the risk that, through loss of existing U.S. and Canadian markets and loss of opportunities for incremental export sales, the Alberta industry will sell less gas in a deregulated environment than it sold under a regulated regime. Economic development can be conceded to U.S. production areas and Alberta development deferred. In that case, Alberta reserves become a store-house for future North American markets, awaiting the depletion of other supply sources at some unspecified future date.

SECTION III: WESTERN GAS' ROLE

In the August 1988 letter, Western Gas described the role that it intends to take in a deregulated gas industry. As a transitional matter, Western Gas is directing the evolution of the Western Gas pool from its traditional status as a supply aggregation providing a high level of security within a regulated domestic market to a new status as an aggregated supply providing a high level of security to any customer that values supply security and is prepared to purchase gas on acceptable terms.

A transitional role also emerges on the supply side. Prior to deregulation, a producer could participate in the Eastern Canadian market only to the extent that it sold gas into the TransCanada supply pool. With deregulation, that role is altered for the pool is no longer a producer's exclusive access to domestic markets. But the objective that deregulation should create a net benefit for Alberta and its producers cannot be achieved unless new long term markets are attached and new delivery facilities are constructed. Freed by deregulation from primary dedication to Canadian markets, the Western Gas pool is now able to facilitate attachment of new export markets and support the construction of required facilities.

In addition, one important effect of deregulation is that, by eliminating exclusive sales franchises, it imposed upon each producer the ultimate responsibility to market its own product. By aggregating a diverse portfolio of markets, Western Gas offers producers a single market with enhanced security of load factor, price and term. A producer selling into the market pool has reduced risk of the impacts of individual market characteristics and events in much the same way that an individual gas purchaser is protected by the supply pool from individual characteristics of specifically dedicated reserves.

The value of this service to producers depends upon the extent to which each can duplicate the function within its own organization. For producers who have the capacity to compete effectively at all levels of the continental gas market, the Western Gas supply pool may represent one more marketing possibility. For producers who are primarily concerned with developing the resource and who may have little or no capability to market gas on a continental scale, the Western Gas supply pool may be the only opportunity to participate in quality continental markets.

SECTION IV: WESTERN GAS' STRATEGY

Western Gas' general strategy is to take a cumulative approach to the development of markets for the Western Gas supply pool. This involves competing to maintain and expand existing markets and building on that base by competing to attach new markets.

With respect to the U.S. Midwest, Western Gas' strategy is to negotiate the extension and reformation of the historical TransCanada/interstate supply arrangements and, at the same time, pursue all reasonable sales opportunities to other customer types. This will involve careful tracking of the U.S. regulatory process to understand how and when the Midwest markets will ultimately be restructured. The general objective is to continue export and sell gas into the Midwest at levels that reasonably approximate historical volumes.

With respect to the U.S. Northeast area, Western Gas' strategy is to pursue the completion of its Northeast gas sales and all matters required to construct a Canadian delivery system to Northeast markets with a view to allocating excess Alberta gas into a major new market

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area. To that end, Western Gas will make a formal request to its producers for support of the ANE gas sale in the next few weeks.

Western Gas intends to pursue any reasonable opportunities to market long term gas supply into California that emerge as the nature of that market becomes better defined.

With respect to Eastern Canada, Western Gas regards it of particular importance to have full flexibility to maintain market share. Such flexibility is essential at least until such time as new capacity to incremental markets becomes available. It is Western Gas' strategy therefore to compete in Eastern Canada markets to maintain market share.

Western Gas believes that the issues raised in this letter and the strategy set forth are critical to the development of the Alberta gas industry and the Western Gas supply pool. The object of the letter is to initiate informed discussion between Western Gas and its producers and, through discussion, to reach some reasonable degree of consensus on the direction that Western Gas will take.

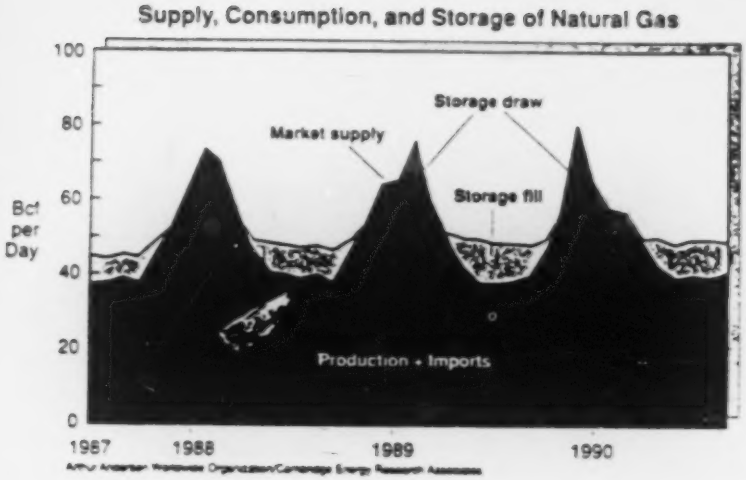
Western Gas encourages you to consider carefully the matters raised in this letter, to discuss its contents with us and to provide us with whatever comments you feel would be helpful on or before Monday, July 10, 1989. Attached to this letter you will find a list of the Western Gas personnel that will be available to discuss any matter arising from this letter.

Yours truly,
WESTERN GAS MARKETING LIMITED

B.G. Luft
Vice-President, Gas Supply

LWS:pzm

Figure 17. *Natural Gas Trends*



The fundamental structural changes that have occurred in natural gas industry since 1985 have brought the seasonal character of natural gas consumption to the fore. In a typical year, U.S. natural gas consumption during the peak winter month is 30 to 35 billion cubic feet (Bcf) per day higher than during lowest month. Yet the variation in monthly production is far less — only 6 to 8 Bcf per day. The difference is largely made up by additions to and withdrawals from storage. Imports of Canadian gas and liquified natural gas (LNG) also account for part of the seasonal fluctuation in demand.

During the winter of 1989-1990, extraordinary weather disrupted the normal winter cycle of storage withdrawals and pushed U.S. production to its highest peak-month levels in several years. Not only was December 1989 among the coldest on record, but the regional incidence of cold weather in the days just before Christmas provided an extreme test of the U.S. gas supply infrastructure. As natural gas demand soared to record peak-day levels nationally, extensive freeze-ins reduced deliverability in the Southwest and Gulf of Mexico. Storage withdrawals of nearly 25 Bcf per day provided the swing that saw the system through with operational problems on only a few pipelines.

By contrast, exceptionally warm weather prevailed during the first quarter of 1990, with the result that storage withdrawals during the first quarter were far below normal. Still, U.S. dry gas production averaged 52.1 Bcf per day during January 1990, significantly higher than in the three previous years. Natural gas imports, including both pipeline supplies from Canada and LNG, have risen significantly over the last several years, and are likely to continue to increase during the early 1990s with the addition of new Canadian pipeline capacity.

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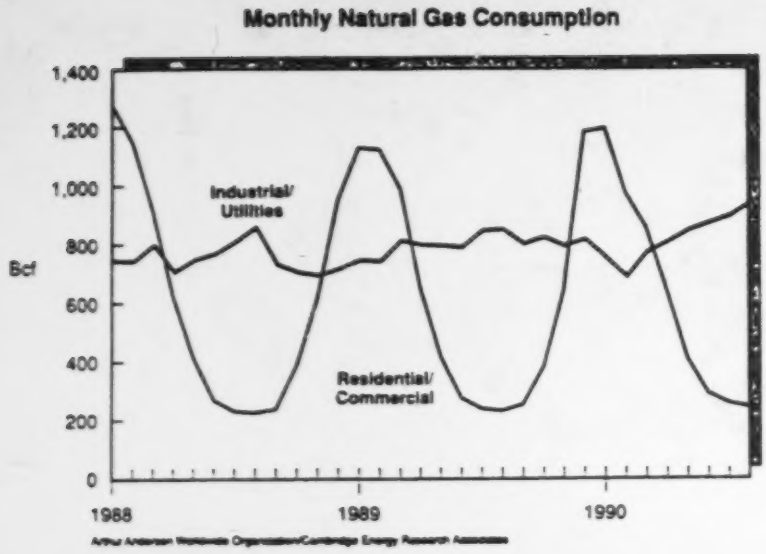
Figure 18.



Since the 1970s natural gas consumption has been increasingly seasonal, reflecting the growing share of the residential and commercial sectors in total gas demand. This trend has caused an increasing reliance on gas storage at peak periods. Gas demand in these sectors, which is primarily for space heating, varies between a combined peak of nearly 1.2 Tcf per month in the winter to just over 0.2 Tcf per month in the summer. Seasonal variations in monthly demand in the industrial sector are much smaller, 0.1 to 0.2 Tcf per month. The seasonal pattern of electric utility demand is the reverse of other sectors due to peak electricity demands in much of the country during the summer. During the winter months, electric utilities in the Northeast and California incur curtailments of gas deliveries as high priority residential customers demand more gas.

In the near term, increasing demands for electric power generation may serve to flatten the aggregate seasonal demand pattern for natural gas. Indeed, gas demand may exhibit dual summer and winter peaks, with the low point in demand being reached in the spring and fall.

Figure 19.

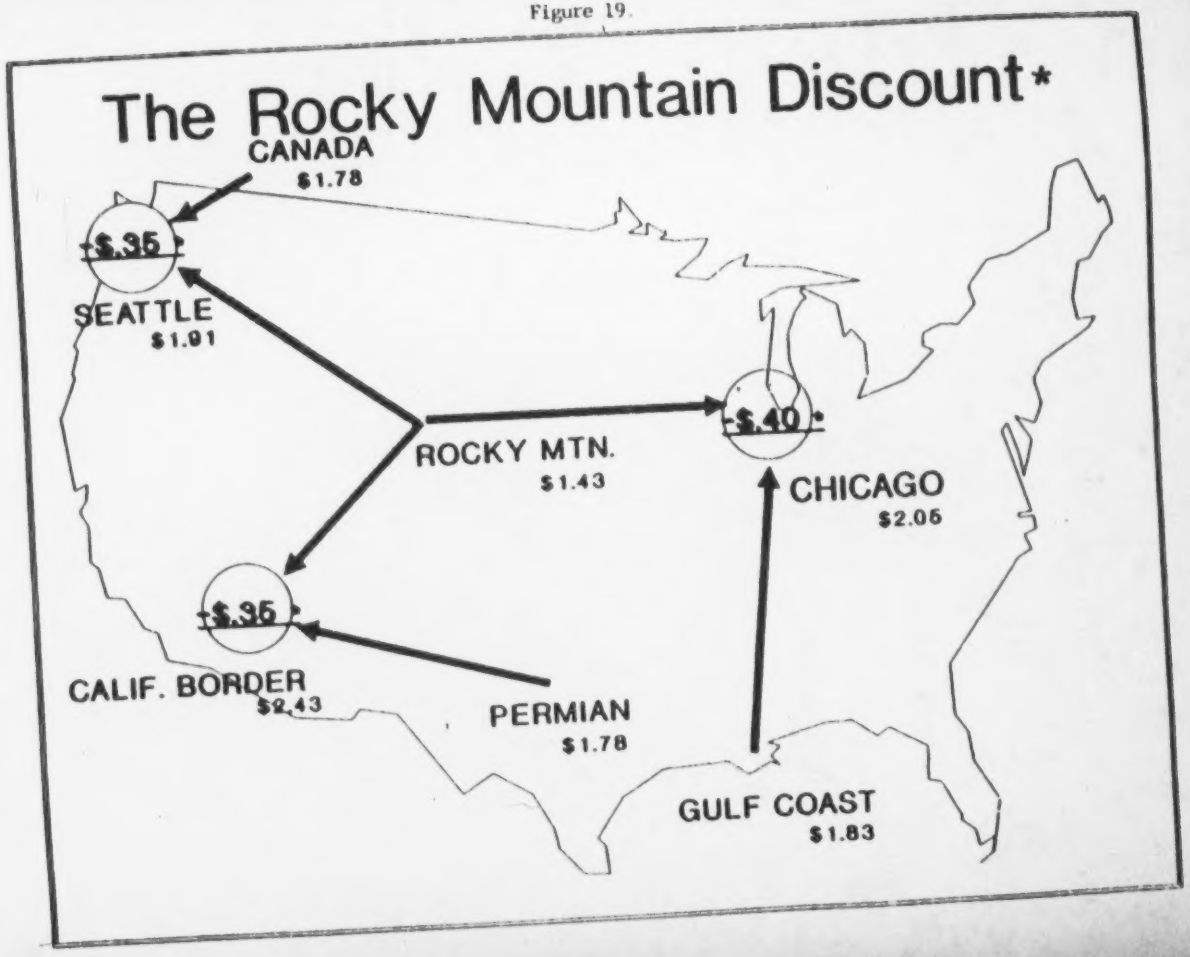

The Rocky Mountain Discount*
CANADA
$1.78
$.35
SEATTLE
$1.91
ROCKY MTN.
$1.43
$.40
CHICAGO
$2.06
$.35
CALIF. BORDER
$2.43
PERMIAN
$1.78
GULF COAST
$1.83

Figure 20.

The Rocky Mountain Discount Effects of Rate Design

- Northwest Market
  Capacity Allocation
  Bundling (Historical)
  Canadian/US Rate Design*

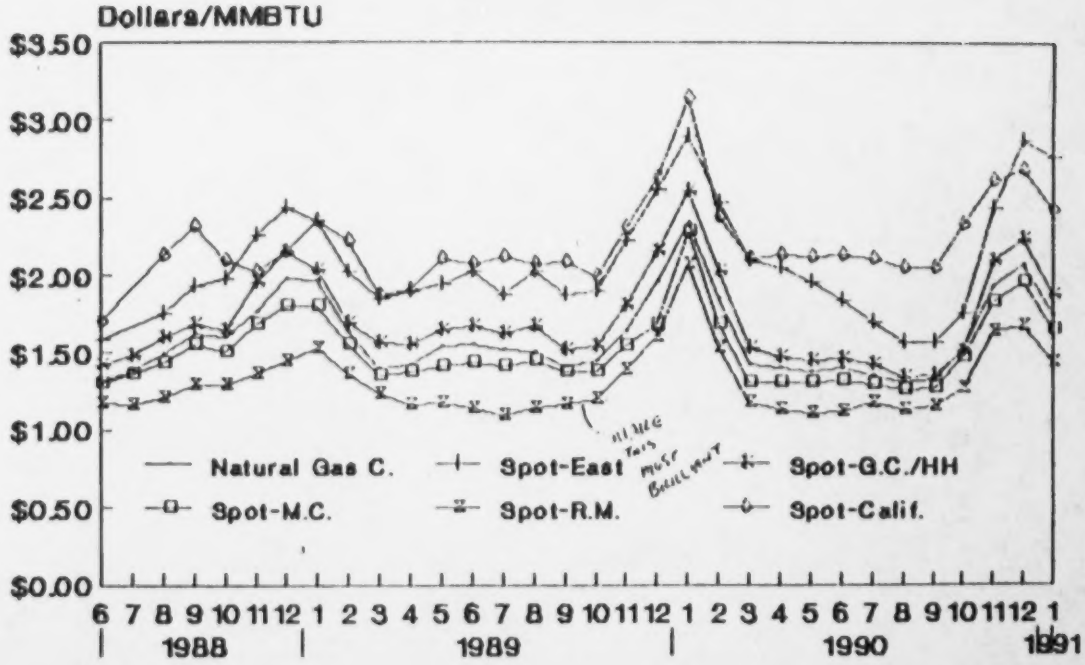
- Midwest Market
  Capacity Allocation
    Challenge/Bump (Historical)
  Rate Stacking
    No joint tariff
  Canadian/US Rate Design*

- California
  Capacity Allocation
  Rate Stacking
  Canadian/US Rate Design*

*Potential

Figure 20.1

NATURAL GAS AVERAGE PRICE COMPARISON



BY REGION

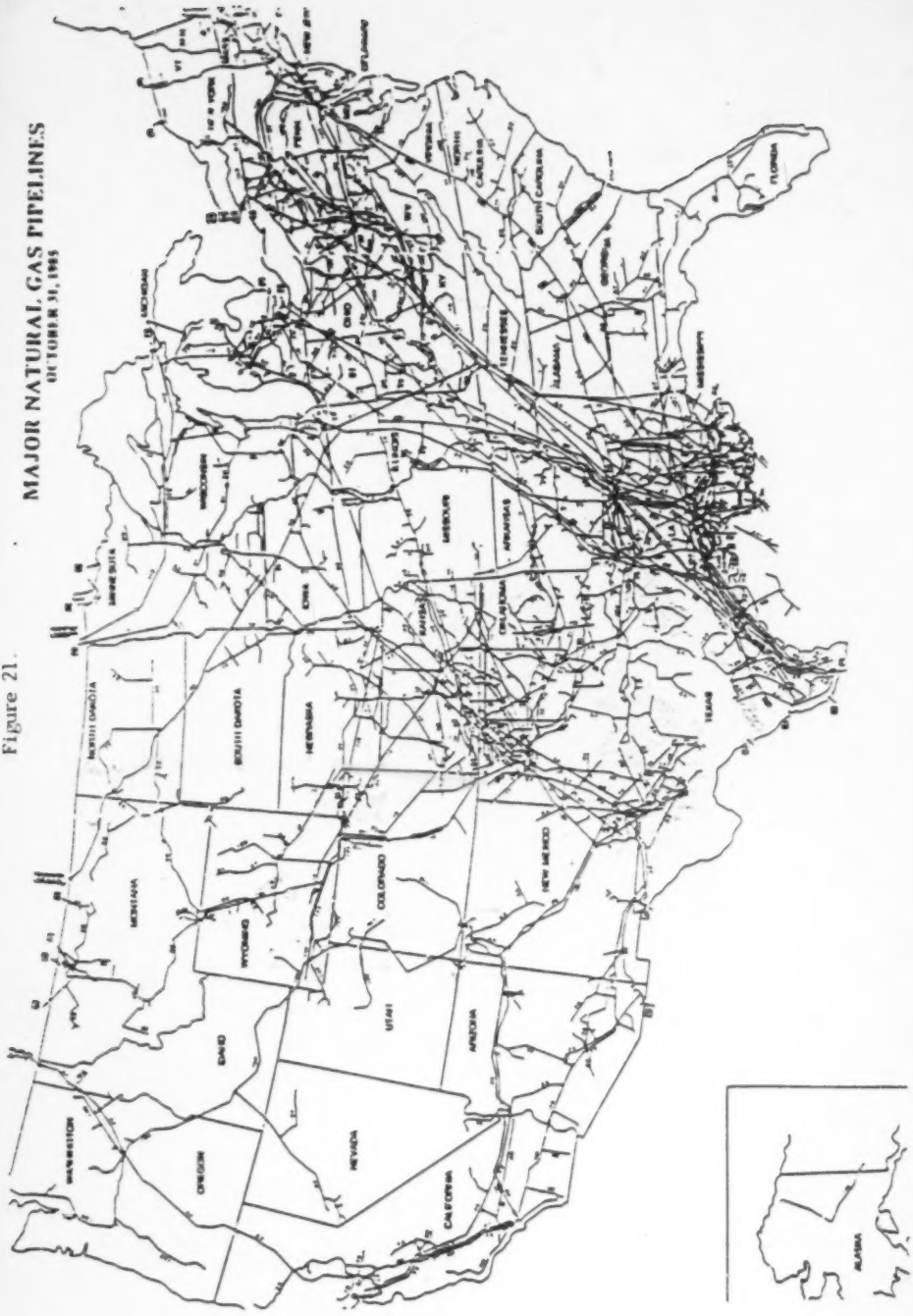
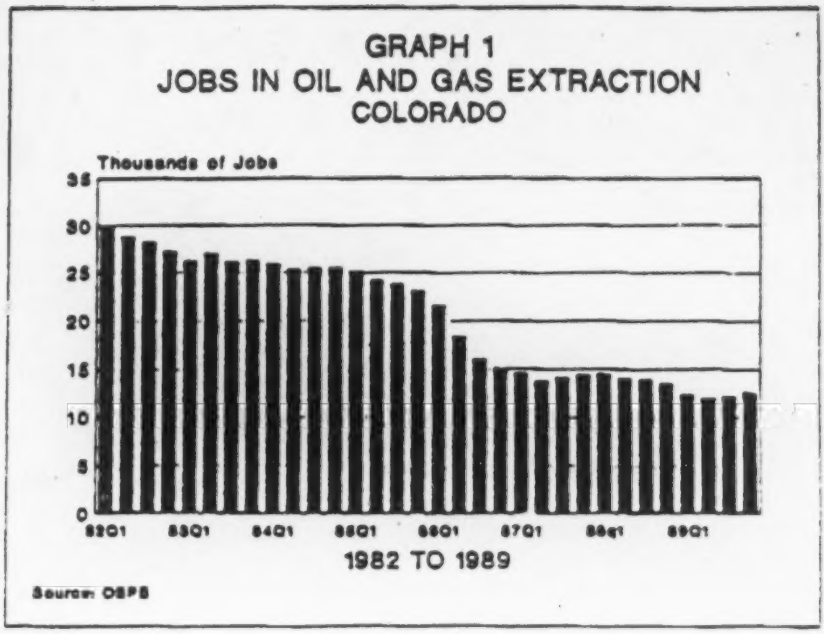

MAJOR NATURAL GAS PIPELINES
OCTOBER 31, 1985
WASHINGTON
OREGON
CALIFORNIA
NEVADA
IDAHO
MONTANA
WYOMING
UTAH
ARIZONA
COLORADO
NEW MEXICO
NORTH DAKOTA
SOUTH DAKOTA
NEBRASKA
KANSAS
OKLAHOMA
TEXAS
MINNESOTA
IOWA
MISSOURI
ARKANSAS
LOUISIANA
WISCONSIN
ILLINOIS
MICHIGAN
INDIANA
OHIO
KENTUCKY
TENNESSEE
MISSISSIPPI
ALABAMA
GEORGIA
FLORIDA
SOUTH CAROLINA
NORTH CAROLINA
VIRGINIA
WEST VIRGINIA
PENNSYLVANIA
NEW YORK
ALASKA

Figure 21.

Figure 22.


GRAPH 1
JOBS IN OIL AND GAS EXTRACTION
COLORADO
Thousands of Jobs
35
30
25
20
15
10
5
0
82Q1
83Q1
84Q1
85Q1
86Q1
87Q1
88q1
89Q1
1982 TO 1989
Source: OSPB

Senator WIRTH. Thank you very much. If you are going to use charts, maybe we could—could you pull those around so we can see them up here as well and maybe if anybody here in the audience—why don't you swing it around so it can be seen there, and the people here might want to move down in that direction. Mr. Vessels' charts are always absolutely stunning. Look at the multicolor charts. If you are color-blind, you are out of luck.

Mr. VESSELS. Thank you. I have provided written remarks, and so I am going to depart from those since everybody is, hopefully, capable of reading them, and I am just going to direct my oral remarks towards the larger picture and the situation that makes Senator Wirth's Gas Policy Reform Act, 662, we feel, very important to the natural gas industry and to our region.

We have to start with, I believe, the market. And as this chart shows, the last 20 years of natural gas market, the market has declined overall. It has recovered somewhat in the last 2 years, but it is still not up to the levels it was in the early 1970's.

This next chart compares the market of natural gas in the Rocky Mountains, and Colorado in particular—right here, this is Colorado, for the last 3 years—and Colorado is as large a natural gas market as we get in the Rocky Mountains. All the other States have smaller natural gas markets than we have.

When we compare this to California, the blue block here, you see that Colorado's market is relatively insignificant compared to one other major State that has a market that we have been trying to access.

On the other hand, we have a very large resource base. Each one of these blocks represents a schematic presentation of natural gas reserves in various States and regional areas of the country. And this is just one part of the Rocky Mountains, the Overthrust area, that you can see—well, you may not be able to see those of you in the audience, but if it is produced at the rates approximate those rates today, it has 160 years of life remaining, more than any other area in the country. And that does not include the coalbed methane reserves which have recently been adding significant reserves to an already large base.

Senator WIRTH. Tom, let me ask you about that.

Mr. VESSELS. Yes.

Senator WIRTH. I thought that the Julesburg Basin was the largest producer in Colorado.

Mr. VESSELS. In Colorado, it may be, although the Piceance Basin and the Colorado portion of the San Juan Basin, when you add coalbed methane reserves and additional tight sand gas reserves, it could be larger than the Denver Julesburg Basin.

In my written testimony, I have included some information from the Gas Research Institute on gas reserves. Several basins, when they say, "speculative reserves" on the far right-hand column, they say, "uncalculated. No estimates available." So there is considerable gas potential from tight sands and coalbed methane that we do not, I do not think, have a firm handle on.

The Overthrust area is established and recognized by all authorities as being a major resource area, which is why it is on here. And we just did not have the time to get the graphs together to present all the resources.

Senator WIRTH. Just looking at that map would suggest that our only reserve is in the southwestern corner of the State where, in fact, I know there is a lot of drilling going on over in the Paonia/Hotchkiss area and in the Julesburg area. We really find natural gas all over the State of Colorado.

Mr. VESSELS. And down in southeastern Colorado as well we do get a piece of the Anadarko Basin come into southeastern Colorado, and there is quite a bit of drilling down there and considerable gas development.

So we have a resource-rich area, but a market-poor area so we have to get out of our market. How do we do that? Well, we use pipelines, and the pipelines—the rate structure and the regulatory structure is what the S. 662 attempts to address.

A Rocky Mountain producer, going back again, for instance, to the Overthrust area, if he wants to get to the Chicago market, he will have to use a multiple series of pipelines to get to Chicago, whereas a producer in an older, more traditional producing province of the United States will only need to use one.

For instance, if you are in the Overthrust, you may very well have to access the Overthrust pipeline, the Wyoming Interstate Company Pipeline, and the Trailblazer Pipeline. Where does that get you to? That gets you to Beatrice, Nebraska. Then, you finally get to access a natural gas pipeline that takes you to Chicago.

And if you were in the Anadarko Basin, you were already on the natural gas pipeline. We get to use four, sometimes six, pipelines to get to market, where producers in more mature regions of the country only needed to use one.

This results in what we do not affectionately refer to as the Rocky Mountain discount. Again, that same Rocky Mountain producer who wants to sell his gas to Chicago—and sell his gas for the same price in Chicago as a producer from the Gulf Coast—is going to sell his gas at the city gate of Chicago, traveling a shorter distance to Chicago—and will end up getting paid 40 cents less per MCF.

This occurs in all the other major market areas, so Rocky Mountain gas is typically being sold at a discount when compared to other gas moving from traditional regions, even, again, if it is traveling a shorter distance.

We feel we have to reform the structure to meet the competition, and we have competition from our Canadian friends to the north. They have been busy. They have been significantly increasing their exports to the United States. In 1987 alone, they increased their exports to this country 33 percent. They are continuing to increase those exports. That is without considering the recent approval of the Iroquois Pipeline and Transcan expansion to the northeast and Pacific Gas Transmissions program to increase their capacity to another three-quarters of a BCF, billion cubic feet per day.

The market we are all competing for—and I hope I have shown there is considerable competition for a market that is not expanding—is very seasonally sensitive. You see here the residential and commercial customers have a sixfold change in their market requirements from summer to winter.

In other words, a residential and commercial customer may be burning as little as 20 percent of the gas in summertime as he will

need in wintertime. To say it differently, he will need six times the gas in winter that he will need in summer.

How do we supply this kind of a customer? Well, one way we have done it is we buy gas in summertime—utilities and pipelines will buy gas in summertime to store and have available when needed for these sensitive customers during their vulnerable time of year in wintertime.

One important aspect of S. 662 for us natural gas producers is that we be allowed to have some mechanism to bridge the gap between selling to markets that can buy very little gas from us in summertime, they simply cannot use it, and bridge that gap to the winter when they will need it and need a great deal of it. The producer demand charge accomplishes this. It allows a producer to be compensated for holding back gas, by example, and having it on demand or on call for the customer when he needs it.

An analogy might be a rental car. You are going to have two charges in your rental car rate: One will be for renting the car and having it for your use; the other one is the mileage, how much you are going to drive the car. The producer demand charge performs that same analogous function.

Utilities and pipelines already can pass on their demand charges to their customers; producers are not currently allowed to do this. This bill would address that and allow us to pass a demand charge on which would again help us to compete with our Canadian competitors.

Finally, my last exhibit is this map. As Del mentioned, you will see that there is a myriad of pipelines in more traditional and older and more mature provinces in the United States. Where the new resource base is, there is very little pipeline infrastructure, and that is what we hope to be able to expand and reform so it works more efficiently. Thank you. I will now turn the testimony over to Fred.

Mr. JULANDER. S. 662, with its goals of stimulating demand for environmentally attractive natural gas for reforming pipeline rate design, for streamlining the pipeline permitting and construction process, and for enhancing the competitiveness of U.S. natural gas, will help a great deal in solving the Rocky Mountain and Colorado and, in fact, the whole country's problems in the natural gas industry that we have and that Tom Vessels has just described. The implications of this bill are significant for Colorado, as natural gas is important to the future of Colorado. I really do not think many of us in Colorado know how significant it can be. Colorado is the headquarters State of the Rocky Mountain gas supply region, which, besides Colorado, includes the northern half of New Mexico, the eastern half of Utah, and the southern part of Wyoming.

This region, as you have heard, has the second highest conventional potential gas reserves in the country, some 120 trillion cubic feet that we know of at this point. If unconventional reserves—that is, coal bed methane and the reserves that are being developed by horizontal drilling—are included, we project that the Rocky Mountain region will have in excess of 210 trillion cubic feet of natural gas, and become the leading repository for natural gas in the United States, ahead of even the Texas region. So we would be the leader.

Now, on top of that, there is a vast amount of tight sands gas in place in the Rockies, over 5,000 trillion cubic feet. We do not yet, as of this time, know how to produce that, but there is a lot of research and development going on, and we believe that within the next 10 years, we will start to produce that.

That would extend this bar in the Overthrust area from 167 years to in excess of 1,250 years.

Senator WIRTH. Describe very briefly the characteristics of tight sand natural gas formations that make it difficult to get to the tight sand.

Mr. JULANDER. Well, it is not a matter of getting to the tight sands as much as getting them to produce, because the reservoir is comprised of very tightly packed grains of sand through which the gas has to flow. We have thousands of feet of this reservoir in the Rockies, yet the technology to stimulate the gas so it can flow through these very small openings.

But we are learning how to do it through such techniques as real-time fracturing, computer monitoring the frac as you do it, as you literally blow the rock apart so the gas can flow out, and through such techniques as horizontal drillings, where you expose more of the formation to the borehole, so you have a greater area to work with and a greater area for the gas to flow out of.

Senator WIRTH. You are saying that in tight sands the potential of that is 40 times greater than the known reserves now; is that right?

Mr. JULANDER. 40 times greater than the known Rocky Mountain reserves, which, in our opinion, are the largest in the country, yes.

Senator WIRTH. Yes. And where are those found? Where are the tight sands formations mostly found?

Mr. JULANDER. They are mostly found in western Colorado and southwestern Wyoming. They are also present, though not in significant amounts, in eastern Colorado along the Front Range.

Senator WIRTH. Are they related to the Piceance Basin and the oil shale reserves in some way? Is the geologic history related to that?

Mr. JULANDER. Probably geologically related. They were both, for the most part, laid down in what are called Cretaceous times, when this part of the country was covered by swamps such as now exist in the southeastern United States, and those swamps laid down both the tight sands and the coal. And we had four major periods in geologic times in our part of the country where this condition existed over millions of years, and it gave us an abundant supply of gas.

Senator WIRTH. Are any other tight sands formations in the country?

Mr. JULANDER. There are some in Texas and there are some in the East, but they are nowhere near as extensive as ours.

Senator WIRTH. The tight sands tax credit was extended in the last budget bill. Is that a useful mechanism? Some have argued that it is not.

Mr. JULANDER. It is absolutely useful. It will encourage people to go out and put capital at risk that they normally would not to learn how to develop this resource which is a domestic resource.

Senator WIRTH. And on the margin, what difference does that tax credit make?

Mr. JULANDER. It makes a difference between, I would say—and I am going to have to go off intuition here because a producer who employs this, and as a member of trade association, whose members do this, I would say that 50 percent of the projects, at least in tight sands, are stimulated by—will be stimulated by the credit over the next few years.

Senator WIRTH. Thank you.

Mr. JULANDER. In Colorado, the oil and gas industry, the gas portion of which is very significant because of the high percentage of gas reserves that we have in this part of the country versus oil, has suffered a great deal of attrition since 1982.

In 1982, we had 30,000 direct jobs in oil and gas exploration in Colorado. Wages in the oil and gas industry are twice, or approximately twice, the average Colorado wage. Therefore, we create a lot of jobs besides the ones directly in the industry. We create two jobs for every job that there is in the industry.

So there were 30,000 in oil and gas extraction, there were over 90,000 Colorado jobs out of 1,300,000 total Colorado jobs at that time that came directly from the oil and gas extraction industry. When you add in the natural gas processing, transportation, and distribution, functions that CIG and Public Service perform, well in excess of 100,000 jobs in Colorado are—were created by the natural gas business.

Here in 1989, the last year that we have——

Senator WIRTH. That is natural gas alone, not oil?

Mr. JULANDER. That figure does include oil because it is difficult to break out the oil portion of the exploration part. When you drill a well, you do not often know whether you are going to get oil or gas. So the best that we can break that out, we would say that at least 80,000 jobs out of the 100 were directly related to gas only. But that is a difficult calculation to make.

Senator WIRTH. Is the natural gas industry now predominant in terms of the oil and gas industry in the State of Colorado?

Mr. JULANDER. Yes. Yes.

Senator WIRTH. How long has that been the case?

Mr. JULANDER. It has happened over the past 2 or 3 years, just as the focus has shifted to natural gas, and as people have started to believe that they will be able to sell their natural gas for a reasonable price eventually. I think we have a chart that will show that.

Senator WIRTH. The reason I am asking is that since I have really gotten embroiled in this more than before, I have been surprised at the size and scope of this industry in the State of Colorado. And I think the more we can pin that down, the more useful that is.

Mr. JULANDER. As you can see, in Colorado, Montana, and New Mexico, the number of gas wells, which are signified in red, completed in 1989 greatly exceed the number of oil wells. I think that is probative.

Senator WIRTH. It is 90,000 or 100,000 jobs, you believe, in the State of Colorado that are directly related to natural gas; is that right?

Mr. JULANDER. Yes.

Senator WIRTH. Now, that would rank where? Do you have any sense of that, Tom?

Mr. JULANDER. Yes, it would rank us—it ranks in the top 10, as you mentioned earlier, and ranks us with such Colorado traditional industries as tourism and basic manufacturing.

We were larger then. Even now in 1989, we are approximately the same size as those industries.

Senator WIRTH. And that is in terms of numbers of employees?

Mr. JULANDER. That is in terms of numbers of employees.

Senator WIRTH. And then the dollar impact of that would track that?

Mr. JULANDER. It has a greater impact because we have much higher average wage in the natural gas and oil and gas industries.

Senator WIRTH. Thank you.

Mr. VESSELS. And, Senator, if I might, too, one of the things that happened to me yesterday when I was seeing those stunning charts for the first time, is I found out one exhibit that I thought I was going to have had been overlooked. I do have in the testimony, it is Figure 6.1, which shows areas containing tight sand—tight gas sands in the United States. So it is in the verbal testimony.

Senator WIRTH. Counsel was just pointing that out to me, a very good map of that. That and all of your testimony will be part of the record.

Mr. JULANDER. The energy sector in Colorado is more important for the United States as a whole, as you might expect with any resource out here. Even today, we employ twice as many people in the natural gas industry than the country as a whole.

In 1982, the natural gas industry, just the natural gas industry, accounted for 6 percent—in excess of 6 percent of the Colorado jobs, and accounted for in excess of 10 percent of the Colorado wage base. We are now down to 2 percent of the Colorado jobs and 5 percent of the wage base.

Our projections show that with the help of the Wirth legislation and the new pipelines that are being built and will be built and the improvement of the national grid system of pipelines, that we can return to these numbers by the end of the century and make that kind of contribution to the Colorado economy.

Colorado stands to benefit economically, and the rest of the country stands to benefit environmentally and economically if domestically produced Rocky Mountain region gas reserves are developed and used in increasing volumes.

We are very supportive of this legislation. We think that with it Colorado can do well by doing good. Thank you.

Senator WIRTH. Thank you very much, Fred. I should note that your new fueling station out by the airport I used only last night for my Jeep. Thank you very much.

Mr. JULANDER. We thank you.

Senator WIRTH. Our final witness this morning is the distinguished president of the Colorado State Gas Company in Colorado Springs, Mr. Jon Whitney. Jon, thank you very much for coming up.

STATEMENT OF JON R. WHITNEY, PRESIDENT AND CHIEF EXECUTIVE OFFICER, COLORADO INTERSTATE GAS CO.

Mr. WHITNEY. Mr. Chairman, thank you very much for this chance to testify. I would also, as the others have, thank you for your leadership in bringing this group together. I have been part of the gas industry for 20 years, and I am sure without your leadership we would not be here today.

As you indicated, I am the president and chief executive officer of Colorado Interstate Gas Company. We operate a natural gas pipeline in six western States. We have been located and headquartered in Colorado since 1928 and do employ over 1200 people, the majority employed in Colorado. We are a subsidiary of the Coastal Corporation, a Houston-based energy holding corporation with operations in virtually all segments of the energy industry.

Along that line, I might add that Coastal Oil and Gas, an affiliate, has recently commenced a 200-well drilling program in the Rocky Mountain States based on the tax credit. So that is a direct result of the tax credit.

I am here today to express our strong support for S. 662, the Natural Gas Policy Reform Act. Natural gas is frequently called the fuel of choice for the 1990's for two reasons: environmental enhancement and energy security. Compared to virtually every other practical alternative, it is the most environmentally sound fuel available today.

As shown in the chart, natural gas, for example, is far cleaner than gasoline in operating an automobile. Moreover, it has multiple uses. Congress recognized the environmental benefits of gas when, in adopting the Clean Air Act of 1990, it turned to this fuel to reduce pollution from vehicles, power plants, and other sources of pollution.

Using natural gas as a clean-air tool will mean that our country will need more gas. The Clean Air Act alone will require an additional 2.5 trillion cubic feet of gas annually, about 13 percent above the current consumption levels by the year 2005.

Natural gas can also enhance our energy security because of our abundant domestic supply. As illustrated in the next chart, we have over 50 years of domestic gas supply at current usage rates, and these resources will grow as technology advances.

Yet, we only have the equivalent of 16 years of domestic oil reserves remaining. An increasing percentage of our oil needs will be met with imported supplies, as you can see from the next chart. By the year 2010, if we do nothing, it is projected that we will be importing 72 percent of our oil needs, up from about 50 percent today.

Natural gas can both help clean up the air and enhance our energy security. But these goals will go unrealized unless changes are made in the way the industry is regulated.

Current laws and regulations have resulted in actual decline in gas usage in the last 20 years. As shown in this next chart, since 1970, the percentage of domestic energy demand met by imported oil has almost doubled, and will nearly triple by the year 2010 if nothing is done.

In contrast, during this same period, the percentage of gas consumed fell by approximately 30 percent, and this decline is expected to continue into the future.

Natural gas is underutilized because of an historical failure to recognize the need for and benefits of competition in the gas industry. As I have explained in my written testimony, this has caused or contributed to numerous problems, ranging from the gas shortages in the 1970's to the gas glut of the 1980's. Today, the failure to make the industry competitive is best evidenced by the need for capacity from wellhead to market.

The present regulatory scheme inhibits choices available to consumers. Moreover, there are insufficient incentives to pursue high risk projects with longer term payouts. Highly restrictive certificate provisions, such as high level factors and low equity returns, are forcing pipelines either to not build projects or to propose projects that are undersized relative to the potential markets.

S. 662 will correct this situation by forming a statutory framework for the enhancement of competition in new services in the interstate natural gas industry. It proposes economic incentives for pipelines to expand, to enhance efficiency, and to offer an ever-growing menu of services to utility consumers, producers, and any other user or shipper of natural gas, while still preserving the FERC's overall role in protecting utility consumers' interests.

The bill also enhances the ability to construct new pipeline projects and encourages the nonconventional use of gas to power automobiles, cool buildings, and other uses. In short, S. 662 will enable the gas industry to meet the dual needs of a clean environment and energy security. Without this bill, the full potential for natural gas will continue to go unrealized.

Beyond addressing environmental and energy security concerns, S. 662 just plain makes good financial sense. First, it will help reduce the trade deficit. $55 billion of the 1990 trade deficit was due to petroleum and related products. And that has nearly doubled since 1986, while the amount of the deficit due to all other goods has decreased from $115 billion in 1986 to $54 billion in 1990.

In other words, imported oil is keeping our trade deficit high, despite the fact that trade numbers for other sectors of the U.S. industry are actually improving.

Second, because natural gas is relatively inexpensive, encouraging its use will save money. Third, promoting natural gas will mean more jobs. And finally, increased competition will produce a more efficient gas industry, which will benefit all consumers. In short, the bill is a win-win for all concerned.

Some have challenged the rate reform and pipeline construction features of the bill claiming they will enable pipelines to charge customers for service using facilities that the consumers have allegedly already paid for and will enable pipelines to bypass local utilities.

As to rate reform, S. 662 would permit, but not mandate, the FERC to consider certain incentive and other rate-making options to establish the current value of pipeline services.

As to construction, S. 662 is intended to expand the competitive options available to the market by facilitating timely construction of new projects. Local utilities will still have every opportunity to

compete in this environment. All will benefit from the competition introduced by this legislation.

We encourage the subcommittee to adopt S. 662. We think it is a win-win for all concerned. And I will be happy now to answer any questions.

[The prepared statement of Mr. Whitney follows:]

PREPARED STATEMENT OF JON R. WHITNEY, PRESIDENT AND CHIEF EXECUTIVE OFFICER, COLORADO INTERSTATE GAS CO.

Thank you for the opportunity to testify. I am Jon Whitney, President and Chief Executive Officer of Colorado Interstate Gas Company. CIG operates a 6,400 mile natural gas pipeline in the six-state area of Colorado, Wyoming, Texas, Oklahoma, Kansas and Utah. We are a subsidiary of the Coastal corporation, a Houston-based energy holding company with operations in natural gas transmission and storage, oil and gas exploration and production, refining and marketing, coal and chemicals, and independent power production. I am here today to express CIG's and Coastal's strong support for S. 662, the Natural Gas Policy Reform Act.

At the outset, Mr. Chairman, I want to thank you for your leadership in bringing together the various factions of the gas industry in Colorado and urging us to develop this bill. As you know, the pipelines, local distribution companies and producers are more often seen battling each other than working together. Nonetheless, because of your involvement, each of the parties put aside their differences and, by working together, were able to forge a consensus on a bill that will enable the industry to provide the country with a clean, domestically produced source of energy for years to come. This would not have happened without your participation, Mr. Chairman, and we thank you.

Natural gas is frequently called the fuel of choice for the 1990's. The reasons for this are simple: environmental enhancement and energy security. Compared to virtually every other practical alternative, natural gas is the most environmentally sound fuel available today. Moreover, it has multiple uses ranging from heating and cooling to power production, and from vehicular to commercial to residential uses.

As shown in the attached chart, for example, natural gas is far cleaner than gasoline in operating an automobile, emitting up to 90 percent less carbon monoxide and 80 percent less reactive hydrocarbons. A study conducted by public service company of Colorado showed even more dramatic results, reducing carbon monoxide emissions by 98 percent. Natural gas can also be used instead of wood in a fireplace, thereby reducing emissions of carbon monoxide by 99 percent, hydrocarbons by 99 percent, particulates by 97 percent and nitrogen oxides by 68 percent. Power plants which operate on natural gas reduce emissions of particulates and sulfur dioxide by virtually 100 percent, and can also significantly reduce nitrogen oxide emissions. When gas and coal are used in combination, such as with cofiring, nitrogen oxides are reduced by up to 75 percent. In short, natural gas is one of the most effective tools our nation possesses to fight air pollution and to reduce emissions of gasses that contribute to global warming. That is why Congress, in adopting the Clean Air Act Amendments of 1990, turned to natural gas to reduce emissions from vehicles, power plants and other sources of pollution. State and local governments across the country are also looking to natural gas to help clean our air. Within Colorado, for example, legislation has been adopted at the state and the local level to require a certain percentage of vehicle fleets to operate on compressed natural gas, and some areas of our state have even gone so far as to ban the burning of wood in fireplaces and require instead the burning of gas or other similarly clean technology.

One thing is clear; using natural gas as a clean air tool will mean that our country will need more gas. According to the American Gas Association, merely implementing the Clean Air Act will require an additional 2.5 trillion cubic feet annually—about 13 percent above current consumption levels—by 2005. Overall national demand for gas is expected to increase from 19 trillion cubic feet in 1990 to 25 trillion cubic feet by the year 2010, an increase of 32 percent. The need for the gas is there—the challenge we are facing is in meeting this demand.

Natural gas can also enhance our energy security because of our abundant domestic supply. As illustrated in the attached chart, we have over 50 years of gas supply at current usage rates. Moreover, the conventional gas resource base is dynamic, increasing in size with improvements in supply technology. This fact, coupled with the increasing reserves found in association with unconventional resources, will ensure abundant supplies of natural gas for years to come.

In contrast, we only have the equivalent of 16 years of domestic oil remaining. An increasing percentage of our oil needs will be met with imported supplies, as the third attached chart illustrates. By the year 2010, if we do nothing, it is projected that we will be importing 72 percent of our oil needs, up from about 50 percent today.

With today's supplies, domestically produced natural gas can, on short notice, displace between 20 and 25 percent of the oil we were importing from Iraq or Kuwait before the war. Longer term, gas could displace up to 12 percent of total U.S. oil imports, or about 6 percent of U.S. consumption.

In sum, natural gas has the potential to enable us to meet two of our most important national objectives: clean air and energy security. But these goals will go unrealized unless changes are made in the statutory and regulatory scheme governing the gas industry. These laws and regulations have resulted in an actual decline in gas usage in the last 20 years. As illustrated on the fourth attachment, since 1970, the percentage of domestic energy demand met by imported oil has almost doubled, and will nearly triple by the year 2010 if nothing is done. In contrast, during this same period, the percentage of natural gas consumed fell by about 30 percent, and this decline is expected to continue into the future. We will never have energy security or clean air if this trend continues.

Natural gas is underutilized because of an historical failure to recognize the need for and benefits of competition in the gas industry. Overly restrictive prices in the 1970's led to a natural gas shortage resulting in gas curtailments and a hesitation to rely on natural gas for energy supply. This was followed by the partial deregulation of wellhead prices of the Natural Gas Policy Act. The NGPA, with its multiple categories of gas, produced rapidly accelerating prices which, coupled with a collapse of oil prices, led to a gas glut. Customers therefore switched freely from natural gas to fuel oil and to spot market purchases in lieu of pipeline supply while pipelines continued to accumulate huge take-or-pay liabilities. That phenomenon was greatly exacerbated by federal regulatory policies which seriously and adversely affected interstate natural gas pipeline companies. As a result, the natural gas industry entered a period in which it lost a large share of its market. Only recently, with the full deregulation of wellhead prices resulting from the Natural Gas Wellhead Decontrol Act of 1989, has the industry even begun to stabilize.

Today, the failure to make the industry competitive is best evidenced by the need for pipeline capacity from wellhead to market. The present regulatory scheme inhibits choices available to consumers. Moreover, there are insufficient incentives to pursue high-risk projects with longer-term payouts. The incorporation of highly restrictive certificate provisions, such as high load factors and low-equity returns, are forcing pipelines to propose projects that are undersized relative to the potential market.

S. 662, the Natural Gas Policy Reform Act, will correct this situation. Specifically, the bill would form a statutory framework for the enhancement of competition and new service in the interstate natural gas industry. Included in this framework are economic incentives for the nationwide pipeline network to expand, to enhance efficiency, and to offer an ever-growing menu of services to utility customers, producers, and any other user or shipper of natural gas, while preserving the FERC's overall role in protecting utility consumers' interests.

The legislation would also address the claim of U.S. producers that they are competitively disadvantaged relative to foreign producers when they are competing with imported supplies. The bill would also enhance the ability to construct new pipeline projects and encourage the nonconventional use of gas to power automobiles, cool buildings and other uses. In short, we feel that S. 662 will enable the gas industry to meet the dual needs of a clean environment and energy security. Without it, the full potential for natural gas will continue to go unrealized.

Beyond addressing environmental and energy security concerns, S. 662 makes good financial sense. First, it will help reduce the trade deficit. $54.6 billion of the 1990 trade deficit was due to petroleum and related products, nearly doubling since 1986, while the amount attributable to all other goods as decreased from $115 billion in 1986 to $54 billion in 1990. In other words, imported oil is keeping our trade deficit high, despite the fact that trade numbers for other sectors of U.S. industry are improving. Second, because natural gas is relatively inexpensive, increasing its use will save money. Third, promoting natural gas will mean more jobs. Finally, increased competition will produce a more efficient gas industry, which will benefit all consumers. In short, the bill is a win-win for all concerned.

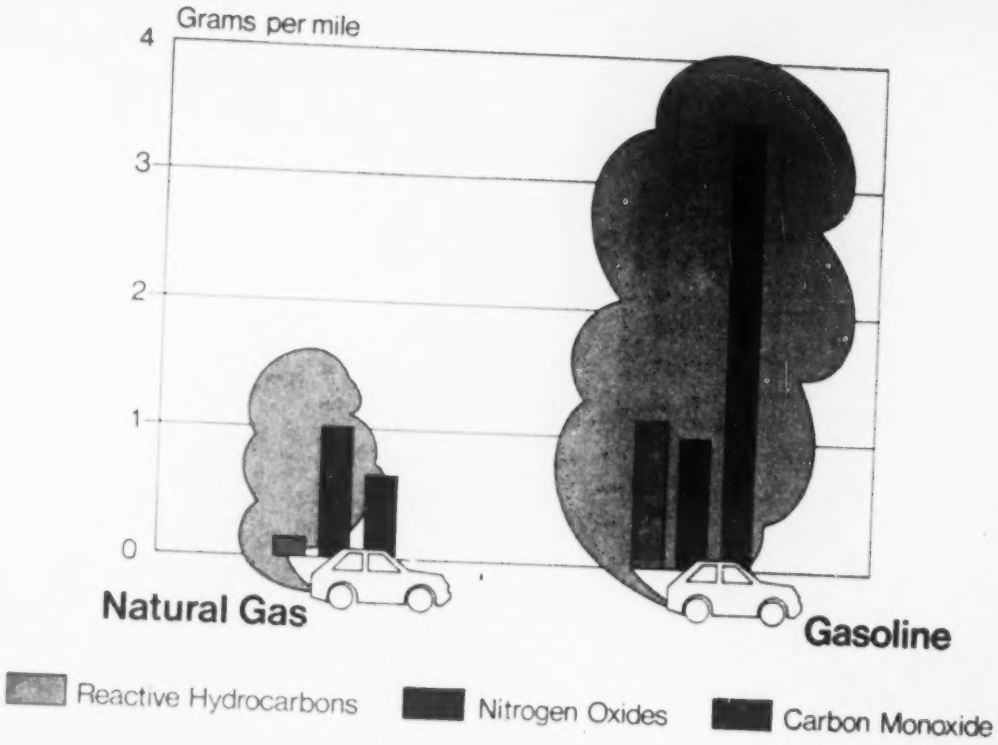
Some persons have challenged the rate reform and pipeline construction features of S. 662. Those interests claim that the Natural Gas Policy Reform Act will enable pipelines to charge customers for service using facilities that the customers have al-

legedly paid for, and will enable pipelines to bypass local utilities. As to rate reform, S. 662 would permit, not mandate, the FERC to consider certain incentive and other rate-making options to establish current value of pipeline service. As to construction, S. 662 is intended to expand the array of competitive options available to the market by facilitating timely construction of new projects. Local utilities will have every opportunity to compete in this environment. All will benefit from the competition introduced by this legislation.

In closing, I want to reemphasize that CIG and Coastal strongly support S. 662, and we encourage its adoption by the subcommittee.

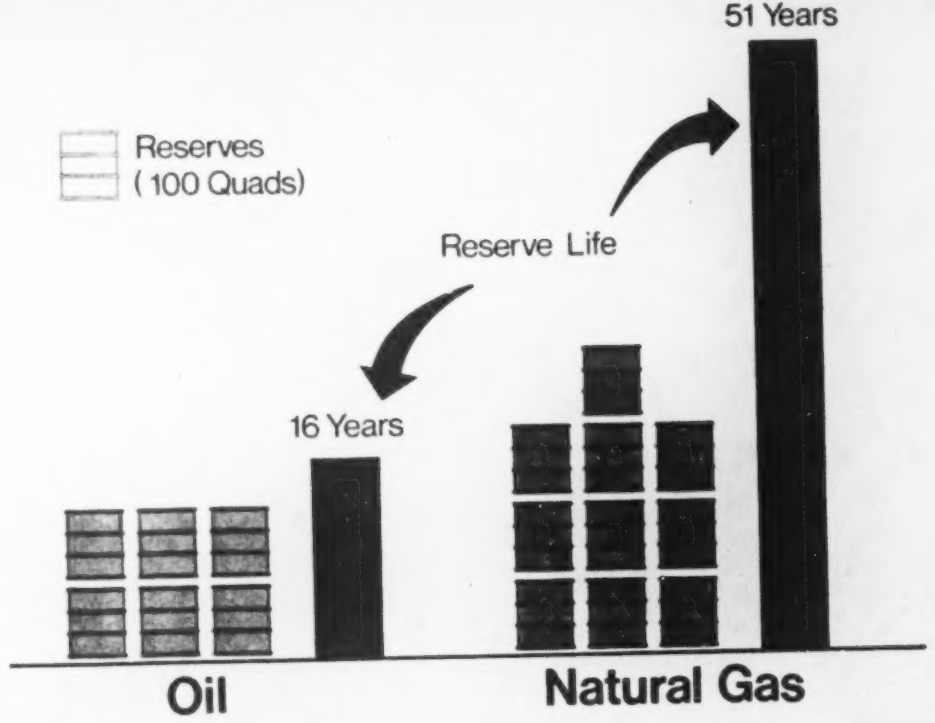
Thank you, and I will be happy to answer any questions you may have.

Vehicular Emissions by Fuel Type



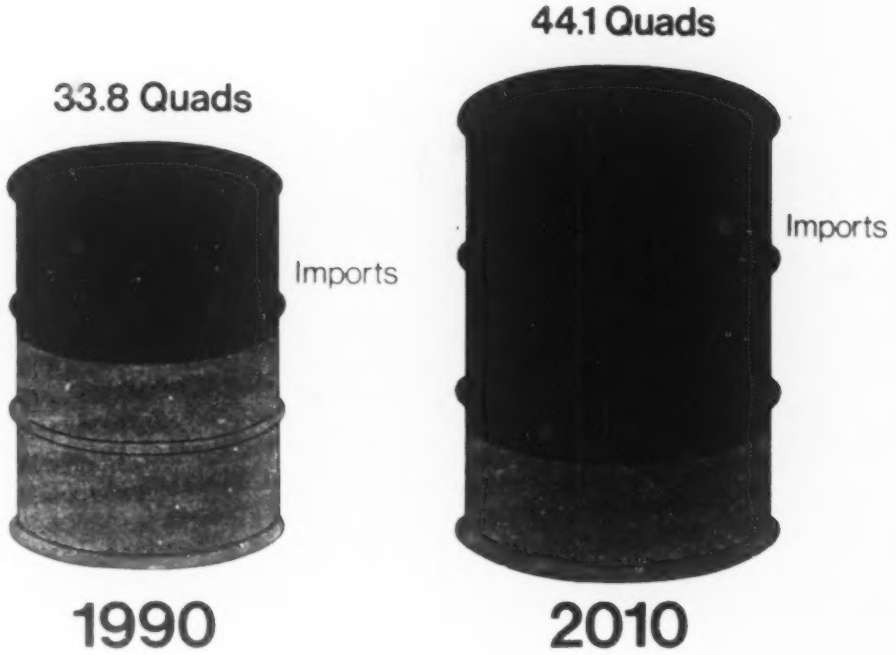
Source: AGA

Domestic Oil & Natural Gas Reserves



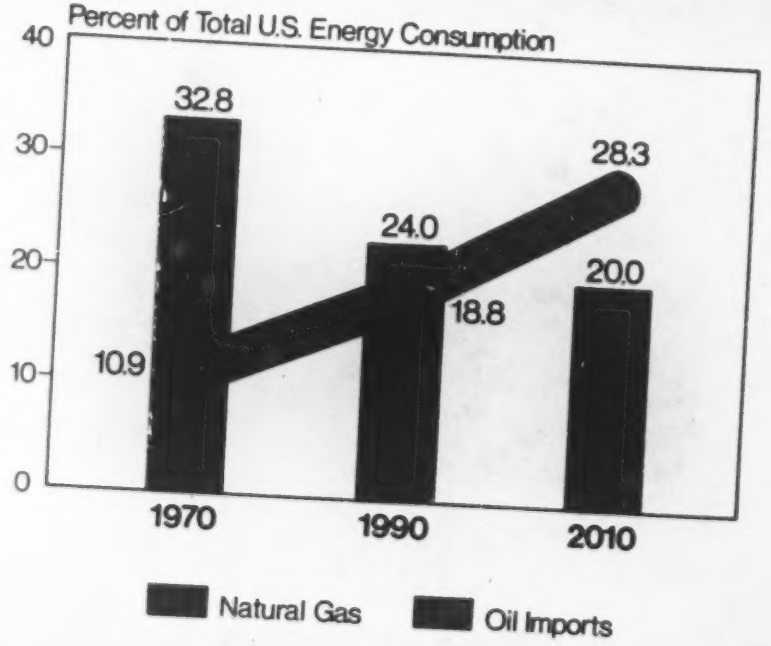
Source: DOE, PGC, API

Increasing Reliance on Imported Oil



Source: DOE

Comparison of Natural Gas and Imported Oil Consumption



Source: DOE

Senator WIRTH. Thank you Mr. Whitney. Thank you very much. Maybe we can just sort of have a discussion here about a series of issues that have come up if that is all right.

Let me start right here, if I can, Jon, with the increasing oil imports and decreasing natural gas consumption in the United States. How would you summarize the reason for that? That would appear to be, just look at that chart and all the numbers surrounding it, that is an extraordinarily illogical position for the United States to be in. We have a domestic fuel that is abundant, which we are using less of. We have an imported fuel that is scarce and more expensive that we are using more of. Why is that?

Mr. WHITNEY. I think it primarily goes back to regulation, and I think that is the opportunity that your bill offers the gas industry. I think we have been overregulated to some extent. I think it has sent the wrong signals.

Senator WIRTH. But the Fuel Use Act, was that a major contributor?

Mr. WHITNEY. That is a partial contributor. I think going back into the 1970's, for example, some of the wellhead pricing provisions that existed back in the 1970's and then in the 1980's sent the wrong signal to the marketplace, causing natural gas not to be developed as rapidly.

Senator WIRTH. What was the wrong signal that got sent to the marketplace?

Mr. WHITNEY. Well, for example, back in 1970, to lead through this, the price of natural gas was constrained. It was held down. And therefore it was a very cheap product.

Senator WIRTH. But it has now been deregulated. Hasn't the price been——

Mr. WHITNEY. Let me lead you through the scenario.

Senator WIRTH. Okay.

Mr. WHITNEY. It was held down and constrained. Therefore, people wanted to use natural gas. However, that led to a curtailment situation where gas was not available. The demand was greater than the supply.

People then became very reluctant to use natural gas because they had been curtailed. So the credibility or the reliability of natural gas as a supply back in the 1970's was questioned because of the regulatory pricing scheme that was imposed on natural gas.

Then, in the 1980's, with the Natural Gas Policy Act of 1978, to overcome that particular regulatory problem, the price of natural gas was increased significantly to encourage drilling, but that, coupled with the collapse of oil prices, in effect meant that gas was then priced too high. So now gas was priced out of the market.

And there was a lot of fuel switching over to oil. And it takes time for the industry to respond to these changes. It is not anything that we could go out and do immediately.

So that the natural gas industry has spent a number of years reacting to past regulatory practices that, I think, have contributed to the current situation that we are in.

Senator WIRTH. Did either of you want to talk about that?

Mr. VESSELS. Yes, I remember in the 1970's—I told my father this morning I had a sense of deja vu here because I remember in the 1970's when it became evident that we were bringing a lot of

additional gas reserves on due to the MGPA, which was also bringing higher prices.

We did not, at the same time, allow large industrial users to get the economic benefits and provide incremental loads for natural gas. They were having to pay full rates for natural gas when they—and we encouraged them to leave and go to coal and heating oil.

We lost—I do not know the exact numbers—but I would say maybe one in three TCF in the market when industrial users around the country switched off of high-priced regulated gas and just went to buy a commodity they could buy freely in competition.

Well, we lost those people permanently. Now, they use natural gas when it is cheaper than their alternate fuel. The Power Plant and Fossil Fuels Act also, as you mentioned, prohibited using natural gas for power generation, so we lost these markets. Fred?

Mr. JULANDER. The history of the natural gas business and how we got in this completely illogical situation is a history of bad public policy and misinformed public policy. We continually shot ourselves not in the foot but right between the eyes for 50 years in this business. Your observation that it is illogical is absolutely correct.

The reason—I think it is important to point out that the reason that we appeared to be running out of gas in 1970 is that gas sold at interstate commerce was regulated. Gas sold in intrastate markets, if you found it in Colorado and sold it in Colorado, you could get what the buyer was willing to pay for it. If the buyer had a choice between coal, oil, electricity, and gas, he would pay you the market value of gas, which was generally three to four times higher than the regulated price.

The regulated price back in those days was 15 to 20 cents per MCF. Today an MCF still is dirt cheap in the Rockies at $1.30 per MCF. In Texas you receive $2 per MCF.

As a producer, if you found gas, it was a headache, because if you were not close to an intrastate line where you could hook up and sell Colorado gas to a Colorado user, you could only get a very, very low price, and you had to scratch your head and say, "Is anyone going to build a pipeline to me? Am I going to have to build a pipeline myself? Am I going to be able to sell this in the interstate commerce at a dirt-cheap price and make any money? Should I just abandon this well as a dry hole and walk away and leave this resource in the ground?"

A lot of wells were abandoned and walked away from because of the low prices, prices that were held artificially low by bad public policy. And it caused the perception that there was not much gas in this country. People back East said, "I can't get gas from Colorado anymore. There must not be any." That is not the case. It is just that all the Colorado producers went broke selling to something below what they paid to find and produce it.

Senator WIRTH. None of you has mentioned take-or-pay. How did that impact on it? Was that part of the regulatory snarl?

Mr. WHITNEY. Yes, take-or-pay occurred in the mid-1980s when the FERC, as part of the regulatory scheme, in effect—this is from a pipeline's viewpoint obviously—broke the pipeline's contract with

its customers, in other words, eliminated minimum bills, eliminated the sales part of the pipeline's market.

The pipeline still had the obligation to buy gas from a producer, but its markets were no longer existing in the same form as before. That led the pipeline into a serious or a huge liability to the producers.

In other words, we had to take for a product we could not sell caused by the FERC regulatory scheme, which led to a lot the issues of hard feelings between pipelines and producers in the last 5 years.

Senator WIRTH. Is it fair to say this anomalous situation arose because there were tremendous irregularities in the pipeline regulatory system that made it difficult for people to depend upon natural gas is a consistent, dependable supply; while that up-and-down was going on and those irregularities in the regulatory process were going on, other markets were being developed that were being filled by the more fungible, nonregulated source of energy; namely, oil? Oil then moved into a lot of those markets that might have been available to the natural gas industry. Is that a fair assessment?

Mr. VESSELS. I would agree.

Mr. WHITNEY. Yes, I think that is a correct assessment.

Senator WIRTH. Okay. How does the Canadian situation fit in this? Now, in the legislation, there are provisions that even out the regulation between how Canadian gas is treated and how U.S. gas is treated. What is the problem that exists between the way—we have what I think is a very smart thing to do, a very good free trade agreement with the Canadians. I think that makes all kinds of sense for us economically. But what are the anomalies in the regulatory situation between how Canadian gas is treated and how domestic gas treated?

Mr. WHITNEY. I think Tom and Fred feel very strongly about that and should probably respond.

Senator WIRTH. You do not, in other words?

Mr. JULANDER. We—the position, at least of many individuals, including the two at this table, we welcome Canadian gas. We welcome it because it provides security of supply and should provide added comfort to the customer.

Senator WIRTH. So you would certainly rather be dependent on the Canadian gas than on the Iraqi oil?

Mr. JULANDER. Right, right. And the customer who's worried that he's going to be facing a shortage of natural gas again is incrementally reassured that he won't be when he knows he's got Canadian gas as well as United States gas. We think that all works to the benefit of the industry.

However, the way the Canadian rates are designed, they put a lot of money down to rent the car, and then they pay a little bit for the mileage. So once you've got the money down for the car, and it just costs you a little bit to drive, then you drive a lot of miles; you buy a lot of Canadian gas.

The United States regulatory system, we put a little money down for the car, and then we pay a lot per mile. So if you have a choice, and you have already made both decisions—the decision to drive

the car that only costs you a little bit a mile is an easy one to make. We——

Senator WIRTH. Who has paid for the car in Canada?

Mr. JULANDER. Pardon?

Senator WIRTH. Who has paid that basic investment for the car in Canada? Who has paid that, versus what happens in the United States?

Mr. JULANDER. The ultimate customer has, and often it is the utility. The utility has contracted with the Canadian producer, has put a lot of money down to rent the car——

Senator WIRTH. You mean the cost of the pipeline, in other words, is built into the rate base for consumers, is that right, at a relatively high level?

Mr. JULANDER. Right.

Senator WIRTH. Whereas, in the United States, the cost of the pipeline is not built into the rate base, so each consumer driving a mile has to pay more per mile, in other words, to transport that natural gas?

Mr. JULANDER. That is correct.

Senator WIRTH. Now, what is the best way to fix that problem? What that does is puts U.S. natural gas at a disadvantage.

Mr. JULANDER. Correct.

Senator WIRTH. Because the Canadians have already paid for their pipeline, so they can ship that gas through the pipeline to the United States very inexpensively. So therefore, can deliver gas in the United States less expensively than you can; is that right?

Mr. JULANDER. That is right.

Senator WIRTH. That is the problem. And then, how do you fix that problem?

Mr. JULANDER. I will speak for myself and our association, and then let Tom speak for his. We would like to see the U.S. rate design changed to be more like the Canadian design. We think it is a more intelligent rate design, and it would even the playing field and encourage the use of gas. We would like to see more on the rent-the-car charge and less in the mileage charge.

Senator WIRTH. Now, we heard testimony on this issue last year. Do you remember it was a very stormy issue. It think it was Iroquois—wasn't Iroquois the issue where this came up?

Mr. VESSELS. Yes.

Senator WIRTH. And the argument was made at that time, and it has never been documented, that this rate design disparity made a difference in the real pipeline, that it was more of a rhetorical battle between natural gas people in the United States and Canada.

Maybe we can ask you to get the IPAM staff or the IPA staff to include for us in the record the documentation on the fact that this disparity really does exist.

As I remember, we had difficulty finding the specific numbers on that a year ago, and maybe those are now available. Do you know, Don, are those——

[A discussion off the record ensued between counsel for IPAMS, Kenneth A. Wonstolen, and Senator Wirth.]

Senator WIRTH. Counsel is saying that IPAA presented some numbers in the Iroquois rate-making decision in front of FERC but that, in fact, there was a lot of controversy about those numbers.

Mr. JULANDER. Ken Wonstolen, our counsel for IPAM, said we do have the numbers. We provided them on the free trade agreement testimony, especially regarding California. So we do have the numbers we can make available.

Senator WIRTH. Great. If you can make those available, we will have the record open. That is an important issue.

Let me jump to a third part of this. Some of this gets relatively arcane, but obviously it is very important. In one of your charts, you showed the seasonal differences in demand for natural gas, and outlined the need for you to be able to store natural gas. Could you explain for the record why it is that you are not allowed to store natural gas, who opposes that, and how you fix that problem.

Mr. VESSELS. Well, actually, I do not know who opposes it, and——

Senator WIRTH. Somebody must oppose it or you would be allowed to do it, or is this an anomaly in the regulatory structure as well?

Mr. VESSELS. May I ask for some consultation from Ken?

Senator WIRTH. Ken, come join us if you want. Ken, for many years, was the executive director of IPAMS, weren't you, Ken?

Mr. WONSTOLEN. Yes. I am Ken Wonstolen, general counsel for IPAMS.

Senator WIRTH. It is always good to bring in the lawyers. You get down to these arcane issues, the lawyers come charging in. I think they create the arcane issue.

Mr. WONSTOLEN. That is right.

Senator WIRTH. Nonlawyers, you know, Vessels and I, understand each other, right?

Mr. WONSTOLEN. You are asking about the producer demand charge, Senator?

Senator WIRTH. I am asking about what happens on the issue of storage. When Mr. Vessels was testifying and looking at the cycles of demand and the need to store gas to meet the wintertime demand, there are apparently some problems that the natural gas industry has in terms of being allowed to store natural gas and being allowed to pay for it, is that it?

Mr. WONSTOLEN. There are really two aspects, from the producer perspective, that you are addressing. One that S. 662 responds to is the producer demand charge. Currently, any fixed charge paid to a first-seller gas producer by the pipeline would be loaded in the commodity portion of the pipeline rate, or the mileage portion in the rental car analogy.

What S. 662 would allow is to have that fixed cost paid the producer loaded in the demand charge portion of the pipeline rate, by analogy the daily fee for the rental car.

The FERC is experimenting with this on their own, and have approved it on an experimental basis for two or three pipelines. They now seem to be backing off it and feeling a little bit uncomfortable, and S. 662 would give them the comfort level to go ahead with their experiment.

The other aspect of the problem really relates to the problem that was identified by Mr. Whitney when the minimum bill was eliminated by the FERC. That is, the utility customer did not have to buy the contract demand from the pipeline anymore. That allowed them to swing off the pipeline merchant service, take advantage of the lowest spot prices in the summertime, in the shoulder months, and then when the winter heating season comes up, call up the pipeline say, "I want my contract serviced."

And that, in effect, then led the producers to be the storage fields because they would have to get—pull back into the pipeline when the contract service was demanded by the local utilities, allow them to have the 30-day spot market available to them in the off months. So by flip-flopping the contract service obligation to the transportation function, which is what S. 662 would do, we eliminate that anomaly, and that will also help us with regard to the storage issue.

Senator WIRTH. And who is going to oppose that provision?

Mr. WONSTOLEN. Well, it is possible that some local utilities and their representatives and possibly some utility consumer groups will oppose that because, in effect, they have been getting free insurance. That is, they do not have to pay the minimum bill—they do not have to pay the insurance premium to have that assurance of supply when they need it. And that's been a free good to them.

They have been extracting that economic rent from the producers and that has been part of the take-or-pay problem. So if someone has been getting free insurance, they may oppose having to pay for that—a premium.

Mr. VESSELS. I think we really do not know what the market will be like if there are more people allowed to compete to offer certain service. In S. 662, one way of looking at it, you would allow more parties to offer a firm demand service to customers, such as I showed, that are very wintertime-sensitive.

More people, you know, large gas producers, should be able, if they wanted to, to enter into contractual obligation to provide gas, for instance, only in wintertime. So, actually, there would be more people able to give that sort of gas service, and that could actually—I mean, when there is more competition, when we have seen gas, typically some rates tend to go down.

I think it would also help us compete with the Canadians because since they have the other kind of structure, we could possibly—a domestic producer, if he could have a demand charge he could pass on to his customers, he might—the mileage rate, to go back to the rental car, we may be able to lower it. And so that maybe we could get closer to the Canadian variable or mileage-based rate.

Senator WIRTH. We are going to have to move on to our next panel. Let me ask you all a final question similar to the one I asked Mr. Hock about the proposals that are made by the administration to move FERC into the Department of Energy. Do any of you have any reaction to that or any recommendations on other changes that ought to be made to be able to speed up some of the processes of FERC? One of the frustrations that we hear all the time is the, you know, if the RTC is bad, FERC is worse in terms of

an agency being able to move and make decisions. Maybe it is not an inaccurate parallel.

Mr. WHITNEY. I guess what Coastal and CIG would like to see is perhaps an assistant secretary in the DOE to represent natural gas, but we think that FERC is a stand-alone agency, and offers an appropriate check and balance.

Senator WIRTH. But that is an appropriate forum where the competing agency can come, and that is a helpful thing to do. Do you all have any reaction to that, Mr. Julander or Mr. Vessels?

Mr. JULANDER. Yes. We would like to see the FERC process reformed. We would like to see more control over the staff. We would like to see the staff have less inertia. And we think that this bill does that. It mandates that the decisions be made that now the staff has been able to dance around.

We would like to see an assistant secretary for natural gas in the energy department, but that is complementing the FERC, and then that secretary could represent the industry and the administration's position at FERC hearings.

The problem with consolidating it all over at DOE is you end up with a benevolent despot, but what happens when the despot is not benevolent? And we have already seen what bad public policy over a long period of time can do to an industry.

Senator WIRTH. Okay. Well, thank you very much. I greatly appreciate your being here and Mr. Vessels, please thank Ms. Plank, your new executive director for IPAMS, and, Mr. Whitney, please thank Mr. Cotten, who is your very able counsel and is well-trained. Thank you all very much for being here and we will leave the record open for any further comments or input you might have.

What I would like to do now, if I might, would be to ask Mr. Schroeder to be joined at the witness table by both Mr. Binz and Mr. Yuhnke and then we might be able to speed up the remainder of the day and have one final panel.

Our witnesses on this panel will be Mr. Mark Schroeder, the Deputy General Counsel for Energy Resources and Legislation in the U.S. Department of Energy in Washington. Mr. Schroeder, we are very pleased that you came out for this and we appreciate that.

Mr. Ronald Binz, the president of the National Association of State Utility Consumer Advocates, who also has extensive involvement on behalf of the consumer groups in Colorado. Mr. Binz, thank you for being here.

Mr. Robert Yuhnke, from the Environmental Defense Fund, Rocky Mountain office in Boulder, Colorado, a distinguished environmental group, with certainly a clear record for all people in Colorado. Mr. Yuhnke, thank you for being here. I understand you also have a time constraint and maybe we could ask you to go first and that would be all right with your two fellow panelists, as I know you have got a scheduling problem as well.

STATEMENT OF ROBERT E. YUHNKE, COORDINATOR, ENVIRONMENTAL DEFENSE FUND

Mr. YUHNKE. Thank you, Senator. We have put together in EDF recently a national transportation program that has been looking

at a number of issues having to do with the effects of transportation use of fossil fuels and the impact that those have on both air quality and global warming. This is part of EDF's new emphasis on the importance of addressing the global warming problem, which I know is one that you feel is very important to address nationally, and we support and appreciate your leadership on that issue. It has been very important to have you in the Congress continuing to focus public attention on that issue.

We, today, are releasing, as part of our testimony for this hearing, a report that we have recently conducted, an analysis of the greenhouse gas impacts of alternative fuels in the transportation sector. This report, which I see counsel has just handed you—I suggest you turn to page 28, Figure 1, which summarizes the conclusions of the report.

Senator WIRTH. And we will, if that is all right, include the report in the record.

Mr. YUHNKE. It has been submitted for the record. I would appreciate it if it could be included.*

What we have done here is to review all of the literature that we could find prepared by various experts in the field assessing the entire fuel cycle emissions of the fuels most likely to be available as alternatives to petroleum-based fuels in the United States during this decade.

So we have looked at methanol, ethanol, natural gas, and electric vehicles, and considered some of the various options that would be available for the production and use of those fuels. One of the most important conclusions has to do with the comparative impact of the use of natural gas.

Natural gas used in an existing gasoline-powered engine, that is the type of vehicle conversion that you have, for example, Senator, in your Jeep, produces no net benefit from the standpoint of the emissions of greenhouse gasses.

And the reason for that is that while we are backing out a lot of carbon dioxide from the combustion of gasoline, we are replacing that with the emissions of methane, which is, in itself, a greenhouse gas 20 times more potent with regard to its greenhouse impacts than carbon dioxide.

So with only 5 percent of the emissions, compared to CO_2, methane will have the same greenhouse gas impact.

When we look at other options for the use of natural gas, for example, using natural gas in a dedicated CNG vehicles, where the engine has been designed specifically to maximize the energy extraction from the natural gas and convert that into power for the engine, we see that natural gas would offer the prospect of a 15-percent reduction in greenhouses gas emissions compared to gasoline, and this is assuming a gasoline fleet of 30 miles per gallon average fuel efficiency.

The best option, however, for natural gas would be to use it in an integrated system where the oil in the vehicle is replaced with electric power, and where the natural gas is used in the power plant to replace coal. That way, we are backing out both the coal from an

* See Appendix.

electric power generating system with a much better fuel from a greenhouse gas standpoint, and removing the oil from the highway vehicle.

Together, that combination can achieve as much as a 36-percent reduction in greenhouse gas emissions. So the point of this analysis—and this type of analysis has been done for the other fuels as well—when we compare all of the options, the one that seems to us to make sense environmentally, at least with regard to global warming policy, is to try to take the limited increase availability of natural gas that could be made available as part of our energy picture in the United States over the next 10 to 20 years, and to focus that limited supply of fuel in a use that maximizes the greenhouse benefits available from the fuel.

So that a policy that focuses on converting existing vehicles, for example, would not be one that we would want to encourage, partly because these changes in our national fuel system are going to represent a major expenditure of capital. It is going to be the type of capital expenditure that we are not going to do frequently. We are not going to change our fuel supply system again in a short period of time if we make a major change now, which I think we are going to have to make because of the shortages of oil, and the need to address national security issues.

So when we make that major capital investment in changing our fuel infrastructure in this country, we need to make sure that the alternatives we choose are going to produce environmental benefits. And natural gas certainly offers the prospect of that, but only if we use it in the ways that minimize the emissions of greenhouse gases.

Now, in this——

Senator WIRTH. You would go to co-firing to get some of that effect, but not as much if you are using natural gas for peak power and for co-firing; you would get some of the benefits, but not as much?

Mr. YUHNKE. If an electric engine in a vehicle were driven by coal-generated electricity, we would actually see an increase in greenhouses gas emissions compared to gasoline. If you use the national fuel mix, which is about 65 percent coal, plus hydro plus some solar, some nuclear, you end up with a 27-percent reduction in greenhouse gas emissions. And if you just look at——

Senator WIRTH. That is the current power plant generation of electricity?

Mr. YUHNKE. Nationally.

Senator WIRTH. And if you had automobiles that ran on electricity coming out of that mix of fuel sources, you would have a 27-percent decrease in greenhouse gas emission?

Mr. YUHNKE. Yes.

Senator WIRTH. But if you went ahead and backed out coal with natural gas, you go from 27 to 35; is that right?

Mr. YUHNKE. Yes. And for the long term, as we look at growth issues, this is also a very important strategy to encourage.

But the key point here is that it is not appropriate to assume that simply encouraging the use of natural gas is necessarily going to give us an environmental benefit.

Another example of that is in the context of air pollution. The chart that you saw earlier demonstrating that natural gas can achieve a much lower emission of carbon monoxide, for example, compared to a gasoline-powered engine is true for those engines or those vehicles that have been tuned and specifically designed to achieve that type of emission reduction.

There are some vehicles that have been tested by the State of Colorado here, for example, that have been converted, similar to the conversion on your vehicle, where no significant improvement in carbon monoxide emissions are being observed. So it is not enough to simply make the change of fuel. You also need to marry up that change in fuel choice with specific standards that ensure that the design of the system, in this case a vehicle, is going to produce the environmental benefits that we would like to see.

Now, this is one of the areas where we were particularly disappointed last year with the Clean Air Act because your amendment promoting alternative fuels would have encouraged EPA, for example, to set much tighter standards to reflect the emission performance potential of these cleaner fuels.

Whereas, now what we are seeing EPA doing is setting a standard for CNG-fueled vehicles that does not improve—or does not require manufacturers to improve the emission performance based on CNG fuel use at all for carbon monoxide. They are still using the same gasoline standard, even though we know those vehicles could be designed to achieve at least a fourfold improvement in emissions.

Now, this comes to some of the key points here.

Senator WIRTH. Let me ask you about the carbon monoxide and the emissions of carbon monoxide using natural gas versus gas. After my car was converted, we took it out to one of the inspection stations and we let it run and it went up and down and did all of the maneuvers.

We ran it on gasoline and then we ran it on natural gas. And with the same testing station, same course—everything was identical—the natural gas emissions of carbon monoxide were dramatically lower. I mean, it was dramatic. I think it was seven times or nine times lower. And that was the same car running on both.

Now, why would that not be the case as this chart suggests?

Mr. YUHNKE. One of the things that Colorado has done, recognizing that these emission benefits are not necessarily inherent in the fuel, but have to be reflected in the design of the conversion kit itself, Colorado has adopted a certification requirement, a regulation that says only certain types of conversion kits can be used or installed on vehicles in Colorado, and those kits are tested to ensure that they produce the kind of emission benefits that we know the fuel is capable of.

But Colorado and California are the only two States in the country to have adopted those types of certification requirements to ensure that the emission benefits are achieved. And for that reason, the conversion program in this State is going to produce an emission benefit, but it does not come just because you change the fuel.

In the kit that you installed in your car, there was a lot of——

Senator WIRTH. That was not certified by the State. That was a Public Service Company kit or a Public Service Company conversion. We had it done in their garage.

Mr. YUHNKE. That is right.

Senator WIRTH. And that was certified, and what you are saying is that the EPA, in terms of alternative fuel kits——

Mr. YUHNKE. In terms of the new standard——

Senator WIRTH [continuing]. In terms of conversion kits has got to set requirements to make sure that those kits achieve the standards that came out of the conversion kit that I had put in; is that right?

Mr. YUNKE. Right.

Senator WIRTH. And you are saying EPA is not doing that; is that right?

Mr. YUHNKE. For carbon monoxide and the benefits potentially available from CNG, they are not doing that, that is right.

Senator WIRTH. And why are they not doing that?

Mr. YUHNKE. Because your amendment lost and they are not required to.

Senator WIRTH. Well, why is it not a logical thing to do that?

Mr. YUHNKE. We think it is very logical to do that.

Senator WIRTH. Who was opposed to that? Let us say, Mr. Schroeder, this was part of a huge amendment Senator Wilson and I offered, and I am finding this fascinating. I did not know the details of this part of it.

Mr. YUHNKE. I think it is partly a response at EPA to the general emphasis in the Clean Air Act amendments on solving the ozone pollution problems of California and the East Coast, and that because of that, they are setting tighter standards to address both hydrocarbons and NO_x emissions.

Senator WIRTH. But if they had had a fix on the global-warming issues, if that had been a priority rather than ozone, or if carbon monoxide had been a priority rather than ozone, they, in fact, then would have said, "Well, we to regulate or we have to certify these conversions"; is that right?

Mr. YUHNKE. That is exactly right. When Congress sets a direction for the agency, they give preference to the outcomes that will be consistent with the direction that you gave them.

And because there was no direction in the 1990 amendments to address the carbon monoxide performance issue, what EPA has done is to focus on those pollutants that address ozone. And since there is an inherent trade-off there between carbon monoxide performance on the one hand and nitrogen oxide performance on the other, they have placed the greater emphasis on improving nitrogen oxide emissions.

And rather than placing on the industry the burden of having to control both, they are saying you do not have to do any better on carbon monoxide. So places like Colorado that have a carbon monoxide problem are not going to see a benefit.

And so this gets down to one of our general concerns with this bill, which is that throughout the bill there really is no instruction either to EPA or DOE to consider the role that standards can play in helping to ensure that the environmental benefits potentially

available from natural gas are achieved, whether it is in the vehicle context or in the utility context.

And we would strongly urge that you consider adding that type of provision or perhaps work closely with the environment and public works committee to look at some companion amendments that could address those types of issues generally.

And secondly, the bill—because I think it is primarily designed to generally promote the use of natural gas, with the assumption that using more natural gas is a good thing, it does not require any evaluation of the relative greenhouse gas impacts of competing fuel options.

And that is something that we would like to see built into the national energy legislation generally, is that the whole question of greenhouse gas impact should be addressed as various fuel options are promoted and as decisions are made either by FERC or by DOE to accelerate the development of certain types of energy technologies.

Senator WIRTH. Just as we encourage or hope to encourage a least-cost path for utility planning and energy strategies, what you are suggesting is that there should also be a least-greenhouse-gas impact?

Mr. YUHNKE. So that when we invest a dollar in a new fuel system, it is also going to produce for us a greenhouse gas benefit.

Now, another example of this problem is that there is a section in the bill that would accelerate conversion of buses, or at least consider the technology for using the alternative—natural gas in buses.

This is one of the areas where using natural gas will definitely not produce a greenhouse gas benefit. As a member of the Alternative Fuels Council, last August I listened to testimony from both Detroit Diesel and Amstar in which they reported their work on developing natural gas alternatives to diesel in truck and bus engines. And their testimony stated that they are seeing approximately a 25-percent loss in energy efficiency when you compare natural gas to diesel.

Now, there are advantages from the standpoint of reducing particulate emissions, which is, right now, the major driving force because of the Clean Air Act requirements that address particulate emissions levels, but from the greenhouse gas perspective, this change to natural gas would actually produce a net increase in greenhouse gas emissions.

So again, the greenhouse gas issue has to be plugged into the decision-making process. If we rely only on, in this case, particulate emissions as the driving factor, we will get a result that may not be consistent with other environmental objectives.

Another key point to focus on here are the provisions addressing WEPCO in this amendment that would essentially relieve those power plants that are being subject to life extension reviews, major modifications that would trigger a review for best available control technology under the WEPCO decision under current law, and combined with the section saying that those utility units subject to 407 of the Acid Deposition Program would only have to meet the standards set in that section, and those units, existing units not subject to 407 would only have to meet low NO_x burners.

The effect of those three provisions together would be to essentially foreclose a major opportunity for using existing law to encourage the substitution of natural gas for coal in the electric-generating industry.

Now, that is an outcome, based on our transportation analysis, that seems to us the most beneficial from both acid rain, urban air pollution, and greenhouse gas consequences.

And we would urge you seriously to consider, in fact, making some modifications to either the energy legislation or the Clean Air Act that would, rather than inhibiting this kind of substitution of natural gas for coal in the utility industry, have the reverse effect and, in fact, stimulate that kind of substitution.

Senator WIRTH. Okay. I was just talking to counsel. We were a little bit confused on your position on the amendment related to WEPCO. You are for it the way it is drafted in the legislation; is that right?

Mr. YUHNKE. No. What we think that the effect of these three sections will do is to foreclose the review of the utility modifications for best available control technology, and that by exempting the existing power plants from that review when they reach the end of their initially expected useful life, where they then would undergo life extension modifications, it has the effect of precluding an evaluation for BACT that would allow the agencies, whether it is EPA or the States, to conclude that BACT really is represented by the use of natural gas rather than coal in that facility because of the inherent emission reduction potential of the use of natural gas compared to coal, and that that will be a regulatory tool that would allow for the expanded replacement of coal with natural gas in the electric power industry.

Senator WIRTH. Let me ask you to make sure that you check with counsel at some point on this, because we have heard some of this argument before, and I am unclear as to whether EPA, under the Clean Air Act, is required to—if you switch to natural gas, is that, in fact, a whole new source that requires a whole new set of permits or not? And I am unclear about that. And what we were trying to do is to obviate that, if there is a switch to natural gas, that is the best available control technology, rather than going on with an older and dirty coal plant.

Mr. YUHNKE. Well, that is what we would like to see happening, but my judgment is that these three provisions taken together would not have that effect.

Senator WIRTH. We can also, I am sure, get Mr. Schroeder to react to this. You are familiar with all of this, right, Mr. Schroeder?

Mr. SCHROEDER. Yes. As you are aware, I think from Dr. Schmalensee's testimony, we are attempting to deal with the WEPCO issues first through a rule making at the EPA and so, for the moment, we are not in a position to advocate statutory change at this time. We want to see how far that rule making can go to address these issues.

I agree, I think, with your counsel and with the chairman that your changes, though, are in the same direction that we are moving with this rulemaking, and that is, that these changes

would not trigger a change in fuel to natural gas, would not trigger any new source requirement for pollutant control projects.

If that is the issue, I think that——

Senator WIRTH. It is. But let us make sure that you all are in touch about this because I think that our intent is the same and maybe the way that the language has been written or the relationship of the three sections you have referred to, Bob, has made it more ambiguous than it ought to be.

Mr. YUHNKE. Well, I think there are two different questions here. One is whether or not an existing law inhibits the conversion to natural gas. To the extent that that is true, and we do not think it is true, but to the extent that that may be true, we would want to eliminate any of that inhibition.

Senator WIRTH. We would all agree on that. We think that that is the case, and we would like to encourage the conversion to natural gas. We think the current law inhibits the conversion to natural gas.

Mr. YUHNKE. But my judgment is that current law will actually stimulate the conversion.

Senator WIRTH. Okay. And then, what is the second point? You said there are two issues here.

Mr. YUHNKE. Well, those are the flip side of the same coin.

Senator WIRTH. Okay.

Mr. YUHNKE. In conclusion, we support efforts to expand the use of natural gas in the American energy sector. And we think that it can provide significant benefits for reducing the emission of greenhouse gases from the United States, but only if the use of that fuel is tailored to those uses that will achieve significant reductions in greenhouse gasses compared to the alternatives that would be available.

And so we strongly urge you to consider making some significant additions to this bill that would encourage that kind of comparison of uses of the fuels to help guarantee that these investments that we make in this fuel switching will have produced the kind of environmental benefits that we think are available.

[The prepared statement of Mr. Yuhnke follows:]

PREPARED STATEMENT OF ROBERT E. YUHNKE, COORDINATOR, ENVIRONMENTAL DEFENSE FUND

My name is Robert E. Yuhnke. I am coordinator of EDF's National Transportation Program, a team of attorneys, scientists and economists from five EDF offices whose mission is to develop and seek implementation of strategies designed to reduce the impact transportation sources have on global warming and urban air pollution.

SUMMARY OF POSITION

Developing alternatives to our current reliance on fossil fuels such as petroleum and coal as sources of energy is essential if modern industrial society around the world is going to successfully establish an energy system compatible with maintaining a stable environment capable of supporting the human population over the long-term. Even though natural gas is a fossil fuel, it can play a significant role in any global strategy to reduce the emissions of greenhouse gases to the atmosphere. But the ways we use natural gas will determine whether it reduces the impact of our energy supply system on global warming.

EDF staff scientist Diane Fisher has just completed a review of the potential greenhouse gas ("GHG") emissions from the alterntive fuels expected to be available in the next ten years as substitutes for petroleum fuels in the transportation sector.

The study compared the expected GHG emissions from natural gas, methanol, ethanol, and electric vehicles. The study revealed some important lessons about the importance of how we use fuels—especially natural gas.

Compared to the GHG emissions from a gasoline-powered fleet with an average fuel efficiency of 30 miles/gal, natural gas-fueled vehicles can provide virtually no improvement in GHG impact on the global atmosphere or can achieve as much as a one-third reduction, depending on the efficiency of the combustion process in which the fuel is combusted, the extent to which unburned methane is lost to the atmosphere given that methane (which makes up more than 90% of natural gas) has a twenty-fold greater greenhouse effect than an equal volume of C_{02}, and whether the natural gas is used to displace fuels with a greater GHG impact.

The range of options we consider in the study include (1) using natural gas as a substitute for gasoline in a traditional gasoline powered engine (the typical vehicle conversion available today), (2) combusting natural gas in a dedicated vehicle for which the engine is designed to maximize fuel efficiency and performance using CNG, and (3) using natural gas to generate electricity which is used to run battery-powered vehicles. The first option—the typical vehicle conversion—achieves no improvement in GHG emissions compared to gasoline because methane emissions from the fuel delivery system and from the tailpipes of converted vehicles offset the reduced CO_2 emissions achieved by switching fuels. In addition, the engine is designed for gasoline and cannot take advantage of the combustion characteristics of CNG.

The second option—the dedicated CNG vehicle—achieves about a 15% reduction in GHG impact compared to gasoline because the engine is designed to maximize the thermal energy conversion efficiency of the CNG and take advantage of catalyst technologies designed to control methane emissions from tailpipes.

The third option—using NG as a source of electric power which then is the primary source of energy to run the vehicle—offers the possbility of reducing the GHG impact by at least 36% compared to gasoline vehicles. This much greater reduction is achieved because oil combustion is replaced at the vehicle and coal combustion is displaced at the power generating station. In addition, NG combustion in the steam boiler results in nearly complete combustion of the methane in the fuel thereby eliminating the methane emissions to the atmosphere that occur from the fueling and tailpipe of a CNG-powered vehicle engine.

These three options demonstrate a very important principle of fuels policy: simply replacing a dirty fuel with an inherently cleaner one does not necessarily achieve an environmental benefit. The context in which the fuel is used and the standards governing its use are essential to determining whether potential environmental benefits will actually be realized in practice.

Another example of this principle is demonstrated by the air pollutant emissions measured from CNG vehicles. Gasoline cars converted to CNG have achieved 90% or greater reductions in carbon monoxide, a serious pollution problem in more than 50 American cities. But some converted vehicles have achieved virtually no improvement in CO emissions and have increased their emissions of nitrogen oxides—another pollutant with serious health and environmental effects—to higher levels than emitted by the same car running on gasoline. Thus conversion to CNG alone provides no assurance that a vehicle will be cleaner, or even that it will comply with federal tailpipe standards.

LIMITED CNG SUPPLY REQUIRES THAT WE CHOOSE CAREFULLY

Because the supply of CNG is not limitless, national policy must be designed to achieve uses of the fuel that will maximize the greenhouse and air quality benefits NG has to offer.

Industry sources estimate that NG gas supply in the U.S. can be expanded from the current rate of about 19 quads per year to 21 to 25 quads per year. In developing its alternative fuels policy, DOE has estimated that NG supply is likely to increase by only 1 quad per year over the next twenty years. EDF's evaluation suggests that 2 to 3 additional guads of NC may be the most realistic scenario.

Three quads of CNG used to fuel converted autos will not contribute to any reduction in GHG impacts, whereas three quads of used as part of an integrated energy strategy to reduce coal burning by utilities and back out oil by replacing gasoline with electric vehicles on the road could become a meaningful plank in a national energy policy aimed at reducing GHG emissions from the U.S.

RECOMMENDATIONS

1. Congress should enact legislation that encourages the use of alternative fuels that will reduce GHG emissions and urban air pollution.

2. To be effective in maximizing the benefits achieved from the use of alternatives, Congress should build standards into any alternative fuel program that allocates incentives to use alternatives on the relative GHG benefit of the use to which the fuel is put.

3. To assure the optimal use of alternatives, EDF urges enactment of a national emission or permit trading program based on GHG emissions similar to the SO_2 emission trading program in the acid rain legislation. Such a program could be based on utility emissions, with a separate trading program for nobile source emissions, or an integrated program for all source categories. But unless national legislation creates a framework in which the GHG emission consequences of various fuel and conservation options are the basis on which economic incentives or disincentives are allocated, there is no assurance that simply promoting the use of a given fuel will produce benefits for the environment.

INTRODUCTION: THE PROBLEM

The U.S. urban transportation system is the major contributor to urban air pollution and accounts for nearly a third of greenhouse gas emissions from the United States. Transportation sources are increasing the combustion of carbon, and the emission of greenhouse gases, faster than any other sector of the U.S. economy.

Emissions from mobile sources impair the health and well-being of Americans who live, work, and play in urban and suburban environments, and threaten to diminish the habitability of the planet. Traffic congestion, endemic in most metropolitan areas as people travel farther from home to shopping and work, intensifies urban air pollution and greenhouse gas emissions at the same time that its delays impose enormous economic and social costs on Americans and firms moving goods by truck.

Harmful concentrations of ozone, carbon monoxide, particulates, and benzene contaminate the urban air supply for 60 million Americans each year. These pollutants cause permanent lung damage, trigger heart and asthma attacks, weaken the body's natural defenses against flu and pneumonia, contribute to sinus irritation and cause cancer. An estimated 10,000 to 50,000 deaths per year are linked to contamination of the human air supply in the United States. Millions more suffer infections, pain, discomfort, lost productivity, and impaired enjoyment of life. Mobile source emissions are by far the largest contributor to contamination of urban air, accounting for more than half of the ozone, 80% of carbon monoxide, half of the particulate and 90% of benzene. Although great progress had been made since the early 1970's in reducing urban air pollution and the 1990 Clean Air Act Amendments will tighten tailpipe emission standards for new vehicles, these tighter standards will not be enough to reduce pollution to safe levels in nine to twenty of the nation's most polluted and most populated cities.

Vehicles are also a major source of greenhouse gas emissions. More than a quarter of the CO_2 emitted by the U.S. to the global atmosphere comes from mobil sources. Although Americans are only 5% of the world's people, they emit more than 20% of the world's CO_2. Per unit of economic production, the U.S. emits nearly half again more CO_2 than some of its leading economic competitors such as Japan and some European countries. A significant portion of the "excess" CO_2, compared to other industrialized nations, derives from the U.S. transportation system which relies primarily on the personal automobile. There are few uses of energy more profligate than moving two tons of steel for every 160 pound passenger.

Transportation-related air pollution and energy consumption are exacerbated by escalating amounts of vehicular driving. In the U.S., transportation is the energy use sector of the economy in which carbon combustion is growing the most rapidly. The miles we drive vehicles in the U.S. is growing about 2.5 to 3% per year, more than twice the U.S. rate of population growth. Vehicular hours traveled (VHTs), reflecting both VMTs and congestion delays, are growing even faster. The increase in VMTs undermines the benefits of improved emission controls on new vehicles, and has played a major role in returning American oil imports to nearly 50% of our national consumption. Before the fuel efficiency standards enacted in 1978 took effect, the U.S. was importing nearly half of all oil consumed. By 1983, oil imports dropped to only 27% of supply in large part because of the dropin fuel demand that resulted from increased fuel efficiency in the national vehicle fleet. Since 1983, average fuel efficiency has contined to climb slowly, but oil demand has skyrocketed again in large part because of the steady growth in VMT.

VMT growth in the future will continue to overwhelm the energy efficiency improvements achieved in engine designs or in other sectors of the economy. For example, average new vehicle fuel efficiency will need to increase to about 40 mpg in

the next decade, and to 55 mpg by 2010, simply to offset the increased fuel combustion that will result from VMT and VHT growth if present rates of growth continue.

The continued increase in VMTs assures virtually no net improvements in total energy use and air pollutant loadings, even in the face of fuel economy and advanced emission control technologies, unless we also take advantage of the GHG and air pollution benefits available from some alternative fuels.

Alternatives, including more efficient and less polluting vehicles, alternative transportation modes including ride sharing, and travel demand reduction strategies, and alternative fuels must all be integrated into a national energy strategy if we are to slow global warming and provide a safe and healthy air supply for all Americans.

Transportation sources directly consume as fuel about 30% of the fossil energy used in the U.S. each year. If the entire transportation-related sector of the economy is taken into account, including the energy required to produce vehicles, replacement parts and fuel, build roads, bridges, planes, airports and ships, and maintain and service the U.S. transportation infrastructure, transportation accounts for about half of all energy use in the U.S.

Virtually all gasoline consumed in the U.S. is used to fuel mobile sources. Gasoline accounts for nearly two-thirds of all petroleum used in the United States. Slightly less than half of all petroleum consumed last year in the U.S. was imported, at a cost of more than $50 billion.

ECONOMY

Since all the fuel options capable of reducing greenhouse gases and mobile source pollution also reduce America's use of imported petroleum fuels, these strategies also promote our national energy security, reduce our trade deficit and help bring jobs in the energy industry back home to America.

ALTERNATIVE FUELS AS PART OF THE NATIONAL ENERGY FUTURE

Alternatives must be part of any strategy designed to achieve national energy goals. Domestic production of petroleum is dropping rapidly, and will continue to decline sharply in the next decades. Of necessity, the U.S. will have to increase the use of alternatives unless we wish to become increasingly dependent on foreign sources of energy.

Domestic sources of fuel include fuel options that offer the potential of achieving significant environmental benefits in addition to increasing national energy security, while other fuels will exacerbate existing adverse environmental impacts from energy use. The environmental community urges Congress to choose energy strategies that will promote both environmental and other legitimate national energy objectives. Energy policy that will result in accelerating global warming, slowing the clean up of American cities, or adding acid pollution (the Clean Air Act has no cap on NO_x emissions) is not acceptable.

The increased use of natural gas (NG) in America's energy future offers promise as one of a number of alternative fuels that reduce the adverse environmental impacts of energy use as well as contributing to national energy security. But simply using more NG without achieving reductions in other more harmful fuels such as coal and oil will not achieve any environmental benefit. Increased NG use will only contribute to achieving environmental goals if it displaces current uses of dirtier fuels.

The EDF is releasing today a report that we prepred to evaluate the comparative greenhouse gas (GHG) emissions of fuels that could replace petroleum fuels in the U.S. transportation sector. Since transportation emissions account for the largest part of urban air pollution and the fastest growing source of GHG emissions in the U.S., as well as over 60% of the demand for oil and oil imports, it is EDF's view that the use of alternative fuels should be targeted on the transportation sector in order to maximize the environmental and energy security benefits of adopting alternatives to current U.S. energy supplies.

EPA has done a reasonably good job of characterizing the air pollution benefits of methanol, NG and electirc vehicles, but little attention has been focused on the comparative GHG emissions of alternative fuels. Since any change in fuels used in the U.S. is likely to involve enormous investments in infrastructure that will take decades to complete and will not be changed easily, it is important that the alternatives chosen contribute to solving such long-term problems as global warming. Therefore EDF has completed an analysis of the fuel cycle emissions of each of the

four major fuel options likely to be available as alternatives to petroleum fuels in this decade. We offer this report as part of the record today.

The report identifies three fuel options as offering the potential for achieving large reductions in GHG emissions from the transportation sector. These include the use of electric vehicles run on electricity from renewable sources, electric vehicles run on power generated from the combustion of NG, and the use of alcohol fuels (either ethanol or methanol) produced from the advanced ligno-cellulose technologies now under development at the Solar Energy Research Institute. NG is the least attractive of these three options, but in combination with the others could play a major role in the development of a future transportation energy system that could eliminate unacceptable levels of GHG emissions from the United States. Once adopted here, it could become the model for the world thereby offering a strategy that could avoid the otherwise inevitable increase in GHGs around the world as global car ownership spirals. See "Driving Forces," World Resources Institute (1990).

Based on the results of our analysis, we present recommendations to the committee set out in our summary above. We thank the committee for this opportunity to present this reaserch, and urge you to work toward the adoption of energy legislation that will promote the multiple goals of nevironmental protection and energy security.

Senator WIRTH. Okay. Thank you very much, and we would certainly appreciate any thoughts or language that you would suggest related to doing that through a least-cost path or least-greenhouse-gas path in the amendment, maybe we ought to be thinking about either on the energy committee or, as you suggested, in concert with the environment and public works commission.

Mr. YUHNKE. Senator, would there be an opportunity to submit supplemental——

Senator WIRTH. Absolutely. The record will be open.

Mr. YUHNKE. Thank you.

Senator WIRTH. Thank you very much, and I know you have a very difficult schedule. Mr. Schroeder, do you have any questions or comments of Mr. Yuhnke while he is here or Mr. Binz?

Mr. Schroeder, you have been very patient, and I appreciate it. We have been trying to accommodate everybody's schedule here, and we appreciate you coming and being present at the hearing.

STATEMENT OF MARK C. SCHROEDER, DEPUTY GENERAL COUNSEL, DEPARTMENT OF ENERGY

Mr. SCHROEDER. It is a pleasure to be here, Mr. Chairman. I want to thank you for hosting this hearing. I am Mark C. Schroeder, Deputy General Counsel at the Department of Energy. I have submitted a lengthy prepared statement which I would like included in its entirety in the record, and I will try to summarize those statements here and be brief.

The National Energy Strategy was developed after an 18-month process, extensive public hearings, probably no undertaking similar to that in many years to solicit public opinion and views on where this Nation ought to be going with energy policy.

We have come out with a proposal which is designed to minimize regulation and taxation, remove regulatory barriers, and permit market mechanisms to work to their maximum so that the public will have maximum energy choices and be able to make decisions as to the most cost-effective and efficient fuel and energy choice available.

In particular, today's hearing focuses on natural gas. This is one area in which, I think, between the chairman, the administration

and other proposals introduced by the members of the committee, we are nearly in accord on where we want to go with this.

Natural gas is abundant. It is economically attractive, and is environmentally preferable as a fuel of choice. Our proposals are to amend the Public Utility Regulatory Policy Act to lift the co-firing limits, which, together with regulatory reforms we have proposed for natural gas pipeline construction and rate making, we believe will create significant increases in demand for natural gas.

In addition, we expect an increase in demand for natural gas through our alternative fuels proposals in which we have proposed an extensive fleet proposal for alternative fuel-capable fleets, a proposal which goes way beyond what the Clean Air Act Amendments of 1990 did. The fleet proposals in the Clean Air Act Amendments affected anywhere from 12 to 21 cities, which varies depending upon regional air quality development. Our proposal will affect almost every major metropolitan area in 43 of the 50 States.

The national energy strategy also emphasizes research and development. Our fiscal year 1992 budget request of $653 million represents a 23-percent increase over fiscal year 1991, and this is just for the national energy strategy-related research and development projects. This figure does not represent total civilian sector research and development funded by the Department.

Our proposals rely on working cooperatively with the private sector through cost-sharing or joint or cooperative ventures, with the belief and the view that where private sector participants are involved, we are more likely to get their cooperation and their interest in bringing new technologies through development to commercialization.

To implement the Alternative Motor Fuels Act, we are currently engaged in a procurement program for the Federal fleet of alternatively fueled vehicles. We are also undertaking joint demonstration and development projects for heavy-duty fleets and with transit authorities for local transportation.

I would now like to turn to some of my comments on S. 662 which are covered in greater detail in the prepared statement.

At the outset, I would like to indicate that we are extremely supportive of the chairman's proposals in the vehicular natural gas area. This was an area not covered in the National Energy Strategy Act submitted by the administration, S. 540.

We think it is important to make clear the limits of State regulation and the limits of Federal regulation with respect to sales of vehicular natural gas. We believe the chairman's bill, together with an additional provision relating to the Public Utility Holding Company Act, which is contained in the more comprehensive legislation introduced by Chairman Wirth with Senator Jeffords, go a long way to addressing some of the regulatory concerns in this area. And we look forward to a dialogue with the committee and the chairman as we move this legislation to markup.

I would like to emphasize one of the research and development projects that both the Colorado community and the chairman and the department are proud of. We are currently engaged in a cost-sharing clean coal technology project with the Public Service Company of Colorado, which is another example of working with the private sector. It is 50–50 cost shared, and it is a gas co-fired

project, which I think is an excellent example of where the national energy strategy's efforts are focused.

At this point we are not advocating statutory change to address the WEPCO issues. At this time, we want to attempt to resolve those issues through an interpretive rule or rulemaking at the EPA, but we are, I think, in accord with the direction of the chair's proposal.

With respect to the proposed changes to the regulatory regime for the natural gas industry, the use of incentive rates, the use of flexible market-based rates, and the deregulation of certain pipeline activities to make markets more competitive are all proposals which are in close accord with those proposed in the national energy strategy.

Similar to the proposals by Chairman Wirth are the addition of a new section 4(g) to the Natural Gas Act in the administration's proposal. The two provisions are remarkably similar, and we look forward to working with the Chair to developing that legislation.

We go farther, though, than the proposals in S. 662. Consistent with our view that the market and market participants should have choices, we have emphasized in our national energy strategy legislation a number of alternatives for new pipeline construction, and having heard the witnesses here earlier today, it appears that new pipeline capacity—the ability to get gas to the market—is of paramount concern to the oil and gas industry in this State, but particularly the gas industry.

We have provided a number of options which allow market participants, both the pipelines and producers, to choose among the most effective and efficient ways to get gas to market. We have proposed allowing negotiated rates between the market participants which would be deemed just and reasonable, which would allow the parties to avoid lengthy FERC hearings and proceedings. The length and delay of these proceedings is often in itself a disincentive to people even pursuing projects.

We believe that, for example, the amendments proposed by Senator Bingaman to S. 341 are substantially similar to those proposed under our optional expedited certificate proposal. Again, we think that there is an opportunity for the administration and the committee to work together on these proposals.

Finally, it is clear that both Senator Wirth's proposal, S. 341, and the administration's proposal all recognize that the process of complying with the National Environmental Policy Act can be improved. We all recognize the valuable contributions that that environmental review, which is required by that act, makes to the decision-making process, but it is a process which has resulted in inordinate delay, and can be greatly enhanced through the proposals in the administration's proposals and in Senator Wirth's S. 662.

To conclude, we look forward to working with you and the members of the committee and subcommittee, and I am now prepared to respond to any questions you may have.

[The prepared statement of Mr. Schroeder follows:]

PREPARED STATEMENT OF MARK C. SCHROEDER, DEPUTY GENERAL COUNSEL, DEPARTMENT OF ENERGY

I. INTRODUCTION

I appreciate the opportunity to be here today to discuss the Administration's views on S. 662, the Natural Gas Policy Reform Act, and pertinent provisions of S. 341, the "National Energy Security Act of 1991," including, in particular, Senator Bingaman's proposed amendments to Title X of that bill.

Mr. Chairman, I would like to say at the outset that S. 662 and the amendments proposed by Senator Bingaman recognize many of the same goals and policies which the Administration's National Energy Strategy (NES) Act, S. 570, embodies. As the Department's General Counsel, Steve Wakefield, testified before the full Senate Energy and Natural Resources Committee on March 7, the Department found in developing the National Energy Strategy broad support for the position that natural gas should be an essential element in our future energy supply mix. It is a domestically abundant, environmentally preferable, and price-competitive source of energy.

Despite these many attributes, we are using less natural gas today than we did 20 years ago. As your legislative proposals and the Administration's recognize, we can improve the regulatory process and minimize regulatory requirements so that we can make full use of this energy resource. We must act now to enact statutory reform to allow the natural gas industry to meet these expected increases in demand and expand its contribution to the Nation's energy supply market. Reform now will help avoid another energy crisis. Failure to act now only assures that we will be revisiting these issues in the middle of the next energy crisis.

Because the Department has already provided the Committee an extensive review of the Administration's natural gas reform proposals, I will not restate them in detail here. However, as background for my comments on your proposals, let me briefly summarize the Administration's bill. It is not an objective of the NES to promote any particular fuel or fuels. Rather, we seek to remove barriers to efficient fuel choices by consumers and to facilitate diversification of the supply mix. To these ends, we have proposed a major program requiring purchases of alternative-fueled vehicles for fleets, which will create a substantial new market for non-petroleum fuels, including natural gas. Enactment of the proposed changes to the Public Utility Regulatory Policies Act (PURPA), to increase the cofiring limits for so-called PURPA projects, coupled with the current desirability of natural gas as a fuel for electric power generation based on its price-competitiveness and environmental advantages, also should result in increased demand for natural gas. In addition, the recently enacted Clean Air Act Amendments also are expected to result in natural gas being the preferred fuel of choice in many new electric power generation projects.

These expanded markets should, in turn, generate demand for more pipeline capacity. Here, the Administration has proposed adoption of a number of options which should facilitate market entry and reduce the regulatory inhibitions and delays which affect many capacity-expansion decisions. In addition to these construction options, we have proposed mechanisms pursuant to which regulated entities may choose to operate in a less-regulated, more market-responsive mode. In return for a willingness to accept the risks of operating in a competitive market, it is only fair that the possibilities of greater returns be made allowable and achievable. In sum, the Administration's natural gas proposals are consistent with the approach throughout the NES Act, recently described by Secretary Watkins as one which minimizes mandates, minimizes regulation, minimizes taxation, maximizes incentives, and maximizes the facilitation of the free market.

II. S. 662, THE NATURAL GAS POLICY REFORM ACT

Mr. Chairman, I would now like to turn to the specific provisions of S. 662. Your bill, like the NES Act, would move the industry to more competitive, market-determined practices. Experience indicates that this will ultimately yield the consumer greater supply at the lowest reasonable cost.

Section 1004 of S. 662 clarifies an area of law with respect to vehicular consumption of natural gas. More specifically, local distribution companies (LDCs), regulated by State commissions, will be able to sell gas for vehicular use without being subjected to regulation by federal authorities. The mere fact that combustion of the gas may occur in another State will not lead to a finding that the gas is not being sold for "ultimate consumption" in the State in which the LDC makes its sale. For those LDCs with service area determinations under section 7(f) of the Natural Gas Act (NGA), the sale would be subject to the exclusive jurisdiction of the State commis-

sion. The Administration supports such a clarification. In addition, though, we believe any such revision should reflect that state regulation is not compelled. Indeed, in order to promote an efficient, competitive market for natural gas as a transportation fuel, it would be desirable to further clarify that the withdrawal of Federal regulatory jurisdiction in this area does not subject gas sales for vehicular use to inadvertent State regulation.

Sections 1005 through 1008 of S. 662 provide several means of promoting alternatively-fueled vehicle use. Deputy Under Secretary Linda Stunts provided extensive testimony on this subject to the full Committee on March 20. Without reviewing here the specifics of each section, I would emphasize that the Administration supports the increased purchase and use of alternatively-fueled vehicles and has included several specific proposals to further these objectives both in the NES and in the NES Act.

However, there are several provisions of S. 662 which the Administration finds objectionable. Section 1005(d) would establish a trust fund to make loans to private companies and individuals to purchase alternative-fuel vehicles or to convert their existing vehicles to alternative fuels. Financing automobile or other vehicle purchases or modifications has never been a government responsibility, and should not be. It is not uncommon for fuel distributors like natural gas companies to provide financing for consumer purchases of equipment that will use their fuel, but this activity is inappropriate for the government. Section 1005(d) should be deleted.

The Department can agree with the basic intention of section 1007, which would provide Federal subsidies to mass transit systems for demonstration of feasibility and safety of specific alternative fuel vehicle types. The proposed authorization is excessive, however, and far exceeds what would actually be necessary for the types of demonstrations that might be undertaken.

Section 1008 is unnecessary in the context of the Clean Air Act and the Administration's proposed National Energy Strategy. Further, it represents an intrusion into the marketplace and an unnecessary subsidy to both vehicle manufacturers and fleet operators. The requirements for gradual conversion of fleets to alternative fuels embodied in the Clean Air Act and the President's National Energy Strategy, combined with a few demonstrations of the type discussed in section 1007 of this bill, are more than adequate incentives, and the authorization of $30 million is unwarranted.

Sections 1010 through 1013, like the NES, contain initiatives for increasing investments for energy technology research and development. We believe that research and development is essential for: (1) reducing the transportation sector's near total reliance on oil, (2) increasing the production of domestic energy resources in an environmentally sound manner, and (3) improving energy efficiency and increasing the range of economical, clean technologies. The Department believes that implementing the enhanced R&D programs outlined in the NES can save 5 to 8 million barrels of oil per day by the year 2030. Included in the enhanced research goal are several advanced gas utilization technologies. The Department's programs, many of which have significant industry cost sharing, address most of the areas highlighted by these sections of S. 662. I will review a selection of those programs that span the Department's efforts to promote the development and commercialization of these technologies.

As part of the Advanced Industrial Concepts Combustion Program in the Office of Conservation and Renewable Energy, research is underway currently, in cooperation with the Gas Research Institute (GRI), to provide a validated basis for design and development of gas-fired pulse combustion technology. Laser-based research tools and computer simulations are used to guide design of high frequency, energy efficient, and low emission pulse combustor devices. In addition, GRI and DOE have planned an Industrial Gas Burner R&D activity to be carried out at the Combustion Research Facility. Research is also underway to provide an improved design basis for spray combustion systems.

In the Clean Coal Technology (CCT) program, the Office of Fossil Energy is supporting efforts in cofiring and gas reburning for NO_x reduction. At Public Service Company of Colorado's Cherokee Power Station Number 3, DOE is cosponsoring a demonstration of a low NO_x burner with reburning to reduce emissions. The project has five industry participants contributing 50% of the project costs. In a second CCT program, with Energy and Environmental Research, the Department is participating in the demonstration of two gas reburning projects that are coupled with sorbent injection for both NO_x and SO_2 control. This project is also 50% industry cost shared.

With regard to natural gas storage, we believe that portions of the horizontal drilling technology under development with DOE and industry have direct application to increasing deliverability from existing underground storage sites.

The NES supports programs to promote transportation fuel alternatives, including natural gas vehicles. Use of natural gas-fueled vehicles will help reduce dependence on imported oil and improve urban air quality. DOE plans to accelerate its efforts in assisting GSA with the procurement of natural gas-fueled light duty vehicles for the Federal fleet as well as accumulating performance and emissions data from all types of fleets. Large Federal purchases of dedicated natural gas vehicles will encourage manufacturers to move toward more rapid commercialization of such vehicles.

Ongoing Department efforts will continue to target development and commercialization of natural gas-fueled buses and heavy duty trucks. Data collection and analysis from a broad range of operating conditions will be carried out at the Alternate Fuel Data Center at the Solar Energy Research Institute. These programs will receive increased emphasis under the NES.

Furthermore, development of advanced engine concepts such as gas turbines, low heat rejection diesel engines using advanced material components and alternative fuel (including natural gas) and fuel cell vehicles will be enhanced as part of the NES initiatives.

The Department believes that a high level of cost sharing at the development and commercialization stage of gas utilization technologies enhances industry's commitment to bring these technologies into the market place. As an additional incentive, the NES will initiate a program that will provide grants for major innovations in energy technologies. The purpose of this program will be to support breakthroughs in specific energy technology areas that can reduce U.S. dependence on imported oil.

There are some provisions of S. 662 which the Administration could not support, however. In section 1010, fifteen alternative-fuel vehicle technologies are specified with the direction that DOE's program should cover at least those. The Department is supporting research in advanced engine types, such as automotive gas turbines and low-heat-rejection diesel engines, and is performing fleet testing of alternative-fuel vehicles, so we do want to see the technologies in these areas move forwards. However, section 1010 should be deleted. If the detailed list of technologies and research area is retained, it is likely to prove counterproductive and disruptive to the advanced research already underway. If the list is eliminated, then the section would more or less duplicate the already sufficient guidance of the Alternative Motor Fuels Act of 1988.

Natural gas use for cofiring is already being demonstrated in the Clean Coal Technology program, and does not need to be redemonstrated as provided for by section 1011.

The Administration agrees with the basic intent of section 1012, which appears intended to revitalize research on natural gas extraction and geoscience. The Administration does not believe, however, that this revitalization depends on increased funding, as provided in section 1012. The President's FY 1992 budget includes a proposal to institute a new natural gas R&D program, industry-driven and based on the use of industry-formed cooperative R&D ventures or research consortia. We believe that a new R&D funding approach is necessary, both to increase private sector participation in the whole R&D process, starting with R&D planning, and to improve technology transfer to the many private-sector players in the gas industry.

Section 1013 provides for Federal support for improvements to all types of heat pumps, heat storage, and replacements for CFCs. The Department has already supported R&D in many of these areas for a number of years, and industry should be in a position to make decisions about commercialization—without taxpayer subsidies—of gas-fired heat pumps and thermal storage systems. The President's budget includes continued support for research on the most energy-efficient CFC substitutes, although the authorization in section 1013 is excessive for that purpose.

Section 1014 addresses the so-called WEPCO issue. As Dr. Richard Schmalensee testified before the Committee, the Administration is seeking to address WEPCO issues through rulemaking activity. We expect to issue an interpretive rule clarifying the application of New Source Review requirements to pollution control projects by June 1, 1991.

As I noted earlier, we strongly support improving the regulatory regime under which the natural gas industry operates. The provisions of S. 662 found in sections 1016 through 1022, on incentive rate designs, flexible rates (i.e., within zones of reasonableness), and deregulating aspects of the interstate pipeline merchant function, are all similar to concepts in the NES Act's natural gas provisions. With respect to

section 1018, however, we do have concerns with the proposed immunity from antitrust law for joint rate filings. The Administration does not believe a specific exemption from the antitrust statutes is needed in this area. To the extent that such joint rates are not anticompetitive or unduly discriminatory, these arrangements should be achievable legally under the existing statutory authorities.

We do agree with the objectives of proposed section 1021, and the NES Act also would make clear that pipeline facilities could be constructed under the authority of section 311 of the Natural Gas Policy Act.

On the subject of wellhead prices, we believe that the Federal Energy Regulatory Commission has the authority now to allow for recovery of gas supply charges, particularly producer demand charges, on an "as-billed" basis, and, indeed, has been moving in that direction. In workably competitive markets, we believe the parties should be free to structure their transactions as they see fit. The NES Act proposes economic deregulation of many pipeline activities when they are conducted in a competitive market. Thus, we agree with the policy objectives of section 1023 of S. 662.

As we have indicated in the past, we believe that provisions such as section 1024, which would subject natural gas imports to standards and scrutiny not imposed on domestic gas production, would raise questions under international trade agreements, in particular the U.S.-Canada Free-Trade Agreement. Under such existing trade agreements no less favorable treatment may be afforded to our trading partners than we afford domestic entities. Therefore, we oppose such proposals including section 1024.

As I indicated in my opening remarks, we strongly support policies which will expedite the construction of new pipeline capacity, similar to those embodied in sections 1025 through 1030. We have proposed in the NES Act a menu of options under which pipelines can choose to proceed with construction, several of which would enable pipeline construction proposals to avoid lengthy regulatory proceedings. We, too, have proposed a resolution for accelerating the process of complying with the National Environmental Policy Act (NEPA), and look forward to working with you Mr. Chairman and members of the Subcommittee on this provision.

Finally, we support the goals of section 1032, which would establish reporting requirements for the identification of State and local barriers to increased natural gas usage. But I can report to you today that the Department already has underway a process of identifying State and local institutional and regulatory barriers to implementing the goals of the NES. This departmental initiative is not confined to the field of natural gas usage, but extends across the range of energy options, and includes supply as well as consumption issues.

III. BINGAMAN AMENDMENTS TO S. 341

As I stated above, we believe the administration of the NEPA compliance process can be improved. S. 341's section 10003(b) is quite similar to the NES Act's section 202, both of which provide for increased reliance on contractor support. Senator Bingaman's amendment would provide that the applicant may procure such contract support directly. Our proposal had consciously avoided this approach, in order to preserve the integrity of the NEPA process and avoid the appearance of conflict. There does not appear to be any legal proscription on the approach proposed by Senator Bingaman, however, and, indeed, we understand that the Interstate Commerce Commission successfully uses a similar approach. In both S. 662 and the proposed Bingaman amendment, we would, of course, expect that FERC would continue to retain its right to independent review and revision of these documents.

We believe the proposed amendment to section 7(c)(1), which would deem contractual commitments for firm service from a proposed pipeline facility as conclusive evidence of the need for the pipeline, is closer to the Administration's proposed optional certificate procedure (section 204) than S. 341 as introduced, and would encourage this subcommittee to consider favorably the NES Act proposal.

The Department agrees that the replacement of deteriorated or obsolete equipment should not require a certificate in all instances, and, in fact, we filed comments to that effect in the FERC rulemaking identified in Senator Bingaman's statement when he introduced his amendments.

We again agree with the objectives of the proposed amendment regarding phasing of proceedings on construction applications. This proposal would codify current FERC practice, and assure that the Commission's efforts to expedite applications will be made permanent.

We do not oppose the objectives of the several amendments which set deadlines for FERC action. Nonetheless, even existing authorities contain deadlines for action,

and experience indicates that there are many tools available to the regulator to avoid such strictures, as many current proceedings indicate.

Senator Bingaman's final amendment would clarify the scope of FERC's NEPA obligations with respect to the environmental impact of non-jurisdictional facilities, which FERC believes it is compelled to examine in light of the *Henry* case. This amendment would limit the scope of FERC's inquiry, which has been viewed as unduly far-reaching by many in the industry, and we support its objectives.

IV. CONCLUSION

Both of the proposals which are the subject of today's hearing are, like the NES Act, initiatives which will advance our mutual goal of increased reliance on and usage of natural gas, which can be achieved if we relieve the industry of outdated regulatory requirements and foster pro-competitive, market-based mechanisms. We look forward to working with you and the members to achieve our mutual objectives.

This concludes my prepared statement. I will be pleased to respond to any questions the Subcommittee may have.

Thank you.

Senator WIRTH. Mr. Schroeder, thank you very much. We really appreciate that, and again, appreciate the very extensive work that Admiral Watkins and all of your staff at the Energy Department did in the 15 months of hearing.

We have taken, as you know, a lot of the ideas that did not get through, perhaps, OMB or the White House that left DOE and did not get any further, we have taken a number of those, as you know, and included them in various energy bills. So I think that there is a great deal of overlap and room for negotiation, and I hope that all of us share this sense of urgency of coming out of the spring with a good, strong piece of legislation to bring to the Senate floor.

Mr. SCHROEDER. We look forward to it. Senator WIRTH. Thank you very much.

Mr. Binz.

STATEMENT OF RONALD J. BINZ, DIRECTOR, ON BEHALF OF THE NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES

Mr. BINZ. Thank you Mr. Chairman. My name is Ron Binz. I am the director of the Colorado Office of Consumer Counsel, and also serving this year as the president of the National Association of State Utility Consumer Advocates. It is also known as NASUCA. NASUCA is an association of 43 state-authorized State advocates in the 38 States and the District of Columbia, and it is their responsibility to represent totally consumer utilities before State and Federal authorities.

We appreciate the opportunity to comment on S. 662, and to provide the perspective of persons who participate daily in natural gas proceedings before both State and Federal regulators.

NASUCA commends Senators Wirth and Bingaman for bringing forth the important natural gas issues raised in 662, in amendments to section 10 of S. 341, and in your other energy conservation bills, Senator Wirth. Our members have been active for many years on many of these exact same fundamental issues in the natural gas industry. In 1985, for example, the Maryland People's Council's successful appeal of an order of the FERC led to Order 436,

which began to open up transportation access on the pipeline system of the country.

We also recognize the importance of natural gas as a clean-burning domestic fuel. Its use, coupled with energy conservation can address many of this country's important energy and environmental concerns, from foreign oil imports to clean air, from acid rain abatement to mitigation of global warming.

At the same time, we are concerned that whenever steps are taken to alter the regulation of the natural gas industry, the needs and rights of utility consumers must be considered.

There is a sector of the consumer energy market, mainly residential and small commercial customers, whose welfare depends directly on the structure and effectiveness of Federal and State regulation of prices charged for the delivery of natural gas. For these customers, the price of natural gas is determined not by negotiations for gas prices, not by the ability to switch fuels, but instead, by the actions of these regulators.

Parts of the natural gas industry are experiencing varying levels of rivalry and competition. But the essential character of the transmission and distribution portion of this industry is still market power, industry concentration, and to some extent, natural monopoly. This is especially true for the residential and small commercial customers of the local distribution companies, who have virtually no supply side alternatives to purchasing natural gas.

NASUCA has substantial concerns about S. 662. While we may agree with many of the goals announced in the bill, it is clear to us that some of these goals, if achieved at all, will be accomplished at substantial cost to the captive natural gas rate bearers. To the extent that the bill shifts risk away from the pipelines and raises rates for our clients, to the extent that the bill increases the market power of pipeline companies or prematurely deregulates services which are essential for the customers we represent, we must oppose those portions of the legislation.

I have submitted for the record a lengthy written statement. I would like to make several points and just elaborate on a couple of them which I think would summarize our position.

As I have said, we believe that the legislation will raise rates for captive customers, primarily residential heating customers of the natural gas pipeline companies. There are three sets of effects which would accomplish that price increase. One is the shift of cost through changes in the rate design. We have heard some testimony on that already. Another is the flowthrough on an as-built basis of the producer demand charges. We have also heard discussions on that. And finally, the sections 1016 and 1019, which will allow pipelines to earn higher margins on firm services, will also raise prices for the customers we represent.

With respect to rate design, section 1016 of the bill casts in legislative concrete portions of a policy statement of the FERC concerning natural gas rate design. In general, the FERC policy statement indicates the agency's decision to begin shifting certain costs to customers of the pipeline's firm sales and transportation services. These costs are known as demand-related costs.

NASUCA members have consistently argued that much of this cost shifting is unfair to the customers of the firm's service. In our

view this tactic by the pipelines, the producers, and the FERC is designed mainly to shift fixed systems cost to those least able to respond to those costs, those with the least elastic demand, and generally reduce the threat of price competition for pipelines and their suppliers.

Most will agree that cost allocation and rate design involves judgment on the part of the administrative agency making this determination, and within the bounds of those discretionary judgments, different public policy outcomes can be achieved.

However, another major component of public utility rates is intercustomer equity. NASUCA believes that shifting costs by loading them on to the demand-related category and then allocating them to the detriment of the small-firm customers without competitive choices violates both the cost causation principles and the equity principles of rate making.

It is noteworthy that section 1016 does not contain the word "equity." Instead, it mandates some of the rate design elements proposed by the FERC, but eliminates consideration of equitable factors, which the policy itself prescribes.

I note in my testimony that there are a couple of other examples in other industries of this shifting of fixed costs. One, probably as notorious as any, is the telecommunications industry, where the monthly access charge for access to the long-distance network, either $3.50 a month or $6 a month, is assessed to all customers regardless of whether they use the network. I think that is a completely analogous type of cost shift.

A similar one occurs in electricity when a utility raises the fixed portion of the monthly charge, as a cooperative in Colorado right now is proposing to do. They are proposing to raise that from $8.50 cents to $18.50 for electricity, and then lower the cost of consumption, the cost for kilowatt-hour charge. So that tactic has, I think, parallels in other industries.

This FERC policy statement represents a high-water mark in the natural gas industry's efforts to shift costs to inelastic customers. It is no surprise that the industry would like to lock in its victory at the FERC and make it very difficult for the agency ever to change that decision.

Whatever the merits of the FERC rate design policy, it seems to us bad public policy to make the regulatory decision the law of the land. If new facts or new policy goals cause the FERC to change its view in the future, it literally will take an act of Congress to permit FERC to modify its rate design policy. In the meantime, residential customers would pay excessive rates for natural gas.

Another point—and I will not spend much time on this, and I elaborated quite a bit in the testimony—a number of provisions of 662, instead of increasing competition, actually increases market power and reduces risk for the pipeline companies.

There are several ways in which that happens, one of which is that we read section 1019 to bar prudence review by the FERC for the cost of construction of regulated pipeline facilities. We are concerned about the abandonment of jurisdictional sales service. The pipelines are allowed, under section 1022, unilaterally to abandon sales service or sales agreements with local distribution companies, which are the monopoly provider to our clients.

Turning to the section on the deregulation of pipelines by the FERC, our concern there is that the bill does not really provide any guidance to the FERC as to what constitutes workable competition. The bill sketches out a mechanism by which the FERC can deregulate pipeline companies—in section 1020—price charged for any sales for resell is deregulated if the FERC finds workably competitive alternatives exist for that sale.

Unfortunately, there are no guidelines as to what constitutes workable competition. In fact, the definition in the bill is somewhat circular. Workable competition is defined to be a degree of competition in the market for natural gas, such that prices can be set by the market and not by regulation.

The difficulty with this definition is that if deregulated, prices will reach an equilibrium set by some sort of market-like mechanism. However, such prices could easily be the result of an action by an oligopoly of companies who perceive it is in their collective interest to keep prices above costs, plus a normal profit.

I think this definition exemplifies what you might call the "if-we-build-it-they-will-come" fallacy applied to regulation. And that view holds that regulation and competition—that view of regulation and competition holds that deregulation in a market with a small amount of rivalry or competition will induce more competition.

In fact, economics show that deregulation in this case may result in an unconstrained oligopoly. It would be far preferable if the legislation contained specific indicia of what constitutes competition sufficient to justify deregulation, or the relaxation of regulation.

In the alternative, the legislation might require the FERC to determine that deregulation actually yield prices which are not higher than the prices which are obtained under regulations, measured as a level of earned return.

Finally, the legislation, in our view, unfairly targets Federal and State regulation as the source of the natural gas industry's failure to sell all the gas it can produce. Instead, regulation is an essential component of an industry which is competitive only partially and only in certain portions of the market.

In several sections of the bill, regulation is blamed for many of the perceived problems of the natural gas industry. Section 1001 finds that regulation and statutory structure has imposed burdens which have resulted in a decline of natural gas consumption which is contrary to the national interest.

Section 1002 promises to improve the situation of the natural gas industry, quote, "by removing or revising burdensome regulatory and statutory provisions which create disincentives to competition."

NASUCA has several general comments about these criticisms of Federal, State, and local regulations. First, we agree that regulation should not be burdensome. In testimony before the Subcommittee on Environment, Energy, and Natural Resources of the House Committee on Government Operations, NASUCA Gas Committee Chair, Margaret Ann Samuels, recently testified, quote, "A major detriment to consumer advocates and to the consumers they represent is the sometimes interminable delays in the FERC decision-making process."

We noted with interest section 1017 of the legislation which establishes a maximum period in which the FERC must take action on an application for rehearing. We are aware of similar provisions in other energy legislation introduced in Congress this year, and we will be considering which, if any, provision to support.

I believe NASUCA members will likely consider a resolution on this subject at our upcoming national meeting.

We seriously doubt the assertion that Federal regulation has acted to curtail the use of natural gas in the United States. Instead, the substantial price increases for natural gas supply beginning in 1973 have caused residential consumers to use natural gas more wisely, practicing conservation, especially for domestic heating with natural gas. In fact, it is far more accurate to say that deregulation of wellhead prices, not the regulation of pipelines, has led to conservation in the residential and small business commercial sector.

This trend is dramatically illustrated in data presented by the American Gas Association in Columbus, Ohio, on Monday of this week. The data shows that the residential natural gas consumption fell 27 percent from 1983 to 1989. Commercial gas consumption fell 21 percent in the same period. And in my testimony there is a graph that shows the intersecting lines of cost increases for delivered natural gas and consumption.

We think it is especially ironic that after inducing conservation with higher prices for natural gas, the natural gas industry now wants to shift further costs to these same consumers in an effort to stimulate new demand for natural gas. And in that sense, the residential customers will be paying higher prices twice; once causing them to conserve, and now again because they did conserve.

Senator Wirth, in summary, we think that parts of this bill insulate pipeline companies both from true competition and from its surrogate cost-of-service regulation. Through the combination of several provisions, the bill could create a natural gas pipeline industry which can achieve supernormal profits without actually undertaking any new projects, becoming more efficient, or increasing the use of natural gas.

Higher profits for the natural gas industry will not necessarily achieve the goals set forth in the legislation. There is no necessary connection between higher profits and any special purposes for this which the firms may put those profits.

Two short examples will suffice. Mobil Oil reacted to higher profits which accompanied the decontrol of oil prices not by drilling for more oil, but by buying Montgomery Wards. Similarly, higher profits in the telecommunications industry are going into a variety of diversified investments. Meanwhile, many State telecommunications regulators are concerned about decline in service quality of local telephone exchange service.

If the intention of the bill is to reward risky pipeline investments with higher returns, much more careful targeting of that effect is needed; otherwise, NASUCA predicts that possibly the only major effect of the legislation will be to increase the bills for residential gas customers and the profits of the regulated pipeline companies.

Senator Wirth, our members stand ready to work with you and the committee staff in this legislation. I would hold out many of

our members as being experts in the consumer side of this issue. We would be happy to be consulted on this issue and appreciate the opportunity today for these interviews.

[The prepared statement of Mr. Binz follows:]

Before the Subcommittee on Energy Regulation and Conservation
of the
Committee on Energy and Natural Resources

Testimony of Ronald J. Binz
On behalf of
The National Association of State Utility Consumer Advocates

Senator Wirth and members of the Subcommittee, my name is Ronald Binz. I am the President of the National Association of State Utility Consumer Advocates (NASUCA). NASUCA is an association of 43 state-authorized consumer advocates in 38 states and the District of Columbia who represent utility consumers before state and federal regulatory agencies and in the courts. We appreciate the opportunity to comment on S. 662 and to provide the perspective of persons who participate daily in natural gas proceedings before state and federal regulators.

NASUCA commends Senators Wirth and Bingaman for bringing forth the important natural gas issues raised in S. 662, in amendments to Section X of S. 341, and in Senator Wirth's energy conservation bill. NASUCA members have been active for many years on many of these exact same fundamental issues of the natural gas industry. In 1985, for example, the Maryland People's Counsel's successful appeal of an order of the Federal Energy Regulatory Commission led to FERC Order 436 and began the process of opening up transportation capacity on natural gas pipelines. NASUCA members regularly appear in natural gas rate case proceedings and rulemakings at the FERC. As recently as January 1991 the Ohio Office of Consumers' Counsel filed comments before the FERC in its docket on rate design. NASUCA presented oral testimony in the same case.

NASUCA also recognizes the importance of natural gas as a clean-burning domestic fuel. Its use, coupled with energy conservation, can address many of this country's important energy and environmental concerns: from foreign oil imports to clean air, from acid rain abatement to mitigation of global warming.

At the same time, we are concerned that, whenever steps are taken to alter the regulation of the natural gas industry, the needs and rights of utility consumers must be considered. There is a sector of the consumer energy market, mainly residential and small commercial customers, whose welfare depends directly on the structure and effectiveness of federal and state regulation of prices charged for the delivery of natural gas. For these customers, the price of natural gas is determined not by negotiations over gas prices, not by the ability to switch fuels, but instead by the actions of federal and state regulators.

Parts of the natural gas industry are experiencing varying levels of rivalry and competition. But the essential character of the transmission and distribution portion of this industry is still market power, industry concentration and natural monopoly. This is especially true for the residential and small commercial customers of local distribution companies (LDCs) who have virtually no supply-side alternatives to purchasing natural gas. Similarly, the rates paid by most LDCs to pipeline suppliers are not determined by market forces (since there is no market) but are constrained to a fair price by federal regulators.

NASUCA has substantial concerns about S. 662. While we may agree with many of the goals

announced in the bill, it is clear to us that these goals, if achieved at all, will be accomplished at substantial cost to captive natural gas ratepayers. To the extent this bill shifts risk away from pipelines and raises rates for our clients, increases the market power of pipeline companies, or prematurely deregulates services which are essential for the customers we represent, we must oppose the legislation.

In the testimony which follows, I will address a number of sections of S. 662. I hope to articulate clearly the concerns we have about several portions of the legislation. NASUCA's position on issues raised in S. 662 is contained in a series of resolutions passed by our membership over the past several years. The relevant resolutions are attached to this testimony and I will refer to them as appropriate.

NASUCA does not take a position on several sections of the legislation, including issues of vehicular natural gas, the environmental review of construction projects and the bill's provision for research and development designed to increase the use of natural gas.

Main Points of the Testimony

I **The legislation will raise rates for captive customers (primarily residential heating customers) of natural gas pipeline companies.**

- Shifts costs through changes in rate design (Section 1016)
- Mandates flow-through of producer demand charges (Section 1023)
- Allows pipeline companies to earn higher margins on firm services (Sections 1016 and 1019)

II **Instead of increasing competition, the legislation actually increases market power and reduces risk for existing pipeline companies.**

- Bars prudence review of facilities constructed under the NGA (Sec. 1019)
- Provides antitrust exemption for joint rates (Sec. 1018)
- Permits abandonment of jurisdictional sales service (Sec. 1022)
- Permits pipeline company to optimize earnings by selecting between regulation and deregulation. (Sec. 1025)
- May restrict import of Canadian gas (Sec. 1024)
- Shifts to consumers the risks of gas procurement and discounts (Sections 1016 and 1023)

III **The bill invites premature deregulation of pipeline companies by the FERC.**

- Provides no guidance to FERC on the meaning of "workable" competition. (Section 1020)

IV **The legislation unfairly targets federal and state regulation as the source of the natural gas industry's failure to sell all the gas it can produce. Instead, regulation is an essential component of an industry which is competitive only partially and only in certain portions of the market.**

V **The bill insulates pipeline companies both from true competition and from its surrogate, cost-of-service regulation. Through the combination of its provisions, the bill will create a natural gas pipeline industry which can achieve super-normal profits without actually undertaking any new projects, becoming more efficient or increasing the use of natural gas.**

I The legislation will raise rates for captive customers (primarily residential heating customers) of natural gas pipeline companies.

Several sections of the bill will combine to cause natural gas rates for captive customers to rise. This will not only harm the interests of those customers, it will produce results which would not occur in a competitive marketplace. In that sense, the bill subverts the role of regulation, changing it from a protector of consumers to a source of higher profits for the regulated industry. In short, the bill will permit the regulators to give the industry what it could not obtain in a competitive market: rates of return which are excessive compared to the risk incurred.

Rate Design Section 1016 of the bill casts in legislative concrete portions of a policy statement of the FERC concerning natural gas rate design. In general, the FERC policy statement indicates the agency's decision to begin shifting certain costs to customers of the pipelines' firm sales and transportation service. The shifted costs are classified as demand-related.

NASUCA has consistently argued that much of this cost-shifting is unfair to the customers of firm service, most of whom are residential and small commercial customers who use natural gas for heating. In our view, this tactic by the pipelines, producers and the FERC is designed mainly to shift fixed system costs to those least able to respond to the costs (those with least elastic demand) and generally reduce the threat of price competition for pipelines and their suppliers.

Most will agree that cost allocation and rate design involves judgment on the part of the administrative agency making the determination. And, within the bounds of these discretionary judgments, different public policy outcomes can be achieved. However, another major component of public utility rates is inter-customer equity. NASUCA believes that shifting costs by loading them onto the demand-related category, and then allocating them to the detriment of small firm customers without competitive choices, violates both the cost-causation principles and the equity principles of ratemaking. (It is noteworthy that Section 1016 does not contain the word "equity." Instead, it mandates some of the rate design elements proposed by the FERC but eliminates consideration of equitable factors which the policy itself prescribes.)

This practice of loading costs on the least elastic customers has parallels in other industries. In the telecommunications industry, the FCC-imposed monthly customer "access" charge shifts fixed costs away from users of the long-distance network and to local exchange customers. These customers, of course, have no choice except to purchase a local line connection from their local telephone company. Residential telephone customers pay $3.50 per month for access to the long-distance network, regardless of whether they actually use that network. Most business customers pay $6.00 per line per month. The charge can be avoided only by cancelling local service: this is not an option anyone wants to exercise. It is not even permissible for a state public utilities commission to offer customers the option to waive both the fee and the right to access.

In the electric industry, cost shifting towards small, less elastic users is also a time-honored

tradition. Here it takes the form of loading costs onto the fixed portion of the monthly charge and lowering the price per unit of consumption. In the 1970's these rates were called "declining block" rates. In the 1990's this cost shifting appears as higher "customer service" charges. In a recent case in Colorado, an electric co-operative, facing increased wholesale rates from its supplier, raised the flat monthly charge from $8.50 to $18.50 and lowered the kilowatt hour charge.

Each of these cost-shifting plans favors large users over the smaller users, favors the customers with elastic demands over others, and generally penalizes the residential customers. Each of these pricing schemes is a version of what is known in economics as Ramsey pricing or use of the "inverse elasticity rule." Each of them attempt to stimulate sales to customers with competitive alternatives while still recovering the total cost of doing business.

The FERC policy statement on rate design represents a high-water mark in the gas industry's efforts to shift costs to inelastic customers. It is no surprise that the industry would like to lock in its victory at the FERC and make it very difficult for the agency ever to change that decision. But whatever the merits of the FERC rate design policy, it is simply bad public policy to make this regulatory decision the law of the land. If new facts or new policy goals cause the FERC to change its view in the future, it literally will take an act of Congress to permit the FERC to modify its rate design policy. In the meantime, residential customers will pay excessive rates for natural gas.

In 1989 NASUCA passed a resolution of the membership calling on the Federal Energy

Regulatory Commission to "return to the legal and equitable principles of the Natural Gas Act and rely on evidence of actual cost in its rate design decisions." I have attached a copy of that resolution to my testimony.

Producer Demand Charges A similar issue is raised by the bill's requirement that any producer-imposed demand charges may be passed on by the pipelines on an "as-billed" basis. This means that charges classified as "fixed" by the (unregulated) natural gas producers will go directly to the recipients of the gas pipelines' demand charges. Once again, these are the firm customers of local distribution companies. The legislation appears to preclude any review of these costs by the FERC or any challenge to them by parties to cases before the FERC. The only exception is when the FERC determines that the pipeline does not offer a "reasonably competitive alternative to its sales service." Even if the FERC is prohibited elsewhere from examining the rate design charged by a producer to a pipeline, at least the FERC currently has the option to assign such cost to the commodity cost category for use in cost allocation. The effect of this section is to ensure that such charges get assigned to customers with inelastic demands. Of note is the fact that these producer demand charges may be levied by affiliated production companies.

This provision, together with the FERC rate design policy creates a "double whammy" for the captive customers. NASUCA recognized this and passed a resolution at its 1990 annual meeting. A copy of the full resolution is attached to the testimony. Quoting from a section of the resolution:

WHEREAS, the flow through of producer demand charges on an as-billed basis will shift risks associated with procurement of a marketable gas supply away from the pipeline and onto its customers;

• • •

WHEREAS, the combined impact of the FERC's policy statement in favor of seasonal rates and the flow through of producer demand charges on an as-billed basis will be to drastically shift costs to heating customers in contravention of the purpose of natural gas regulation which is to protect customers from excessive prices;

WHEREAS, the FERC's actions are particularly egregious where it has allowed the flow through of affiliated producer demand charges on an as-billed basis;

• • •

THEREFORE, BE IT RESOLVED, that the National Association of State Utility Consumer Advocates (NASUCA) opposes the Federal Energy Regulatory Commission's policies allowing for the flow through of producer demand charges on an as-billed basis.

BE IT FURTHER RESOLVED that NASUCA urges the FERC to, at a minimum, deny the flow through of affiliated demand charges on an as-billed basis.

Valuation of Rate Base Rates for all gas customers will rise under another provision of the bill. Section 1016 permits the FERC to use replacement cost or market valuation as a measure of a pipeline's rate base. Instead of basing rates on the actual cost of a pipeline's investment, the FERC can allow rates to rise to a level reflecting a return on investment never made by the pipeline. Rates will be deemed to be just and reasonable if they fall within a zone, the upper bound of which is determined by rates which recognize "current market valuation" of a pipeline's investment.

To see how unfair this provision is, we must realize that pipeline customers have been paying

depreciation expenses of pipelines to reimburse the pipelines for the cost of their investment, together with a rate of return on the undepreciated balance. These depreciation payments have begun to reimburse the pipelines for the original cost of the investment (including reinforcements, rebuilds and improvements). It is clearly unfair to change the rules of the game now and decide that the investment cost of the pipelines is not really the cost to be paid by consumers.

By using the term "current market valuation" in this section, the legislation appears to be causing rates to comport with market conditions. However, the effect of using an inflated measure of rate base is no less pernicious than merely inflating the regulated company's rate of return. In a later section of this testimony I will discuss the concept of a fair rate of return on investment and demonstrate how this rate base valuation issue is connected to what a firm in a competitive market would earn on its investment.

II Instead of increasing competition, the legislation actually increases market power and reduces risk for existing pipeline companies.

Pre-granted Abandonment Section 1022 of the bill significantly strengthens the hand of the pipeline companies when negotiating with their local distribution company customers. This provision allows the pipelines to abandon jurisdictional sales service to a customer upon expiration of the underlying sales contract. Since many, if not most, LDCs have no truly competitive alternative to their pipeline suppliers, whether through sales or transportation, this

provision tremendously enhances the pipeline's power when negotiating terms and prices with the LDCs.

NASUCA recognized this danger in previous proposals to enhance the pipelines' market power by permitting pre-approved abandonment of firm transportation contracts upon expiration. In a resolution passed by the membership in 1990 the members cited the court's reasoning that the use by pipelines of pre-granted abandonment exposed transportation customers of the pipelines to the abusive exercise of monopoly power of the pipelines. NASUCA is pleased that S. 662 will require FERC approval before a pipeline may abandon jurisdictional transportation service which was previously converted from jurisdictional sales service. However, we are troubled by the parallel provision which allows pipelines to abandon sales service without FERC approval. I have attached a copy of the resolution to the testimony.

"Fair Return" and Prudence Other features of the bill shift risk (both market risk and regulatory risk) away from the pipeline companies. First, the FERC is instructed in Section 1022 to base rates on a rate of return applied to all the assets of a pipeline which are "used and useful" in fulfilling its utility function. At first glance this provision seems merely to codify the practice of requiring utility property to be actually used and useful before being added to rate base.

Upon closer examination, it is clear that the section may bar the FERC from finding that any used and useful property was imprudently constructed. In other words, Section 1022 ensures that a pipeline company will earn a return on the full amount expended for a project,

regardless of the project's cost, and regardless of the degree to which the property is used or whether the project represents excess capacity.

When three particular sections of the bill are taken together, it becomes clear what a fundamental blow the bill would deal to cost-of-service regulation. A pipeline could construct facilities without a certificate under Section 1021, later seek FERC inclusion in cost-of-service ratemaking under Section 1025, and then, by Section 1019, receive a full return on the project. Assuming the FERC goes along with the plan, this is a way of insulating a pipeline from all risk that a project will not be successful.

Antitrust Exemption Section 1018 grants natural gas pipelines an exemption from the Sherman Act to permit them to file joint rates for transportation of gas to market. While this section may be a creative way to get around the divisive issue of postage stamp versus mileage-based rates for transportation, NASUCA is concerned that this provision is the legislative equivalent of killing a fly with a sledge hammer. NASUCA is concerned that granting an exemption to the Sherman Act will produce a variety of anti-competitive outcomes. If an antitrust exemption is eventually determined to be the only approach to the situation, then the scope of the exemption must be very carefully circumscribed.

Natural Gas Imports The section of the legislation on imported gas is a cause for concern among consumer representatives. In general, natural gas consumers will benefit to the extent that the availability of Canadian gas exerts competitive pressures on American producers and pipelines. In our view, such restrictions should be applied very sparingly.

Automatic Pipeline Construction Section 1025 allows a pipeline company to construct facilities without prior approval of the FERC if the company holds a certificate of public convenience and necessity (CPC&N) and has agreed to provide open access transportation pursuant to that CPC&N both for existing facilities and for new facilities constructed under the section. However, the provision also permits pipeline companies to seek a CPC&N for such Section 311 facilities. These two provisions mean that the pipeline companies can optimize their earnings inside and outside of regulation. Projects with low risk or high yield can be built without regulatory approval and without subsequent regulatory controls over profits. Projects with higher risk or lower returns can be subsidized by applying to bring them under FERC regulation at the pipeline's option.

Taken together, these provisions of the bill add up to one thing: less risk for pipelines and their suppliers. Less risk should mean lower returns and, for consumers, lower rates. In this case, though, lower risk is achieved by forcing all the risk onto the natural gas consumers, yet the pipelines retain the protections of regulation when it benefits them.

III The legislation invites premature deregulation of pipeline companies by the Federal Energy Regulatory Commission.

The bill sketches out a mechanism by which the FERC can deregulate pipeline companies. In section 1020, the price charged for any sale for resale is deregulated if the FERC finds that "workably" competitive alternatives exist for the sale.

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Unfortunately, the legislation offers the FERC no guidance as to what constitutes "workable competition." In fact, the definition provided in the bill is somewhat circular. "Workable competition" is defined to be a degree of competition in the market for natural gas such that prices can be set by the market, and not by regulation. The difficulty with this definition is that, if deregulated, prices will reach an equilibrium and be set by a market-like mechanism. However, such prices could easily be the result of the action of an oligopoly of companies who perceive that it is in their collective interest to keep prices above costs plus a normal profit. This definition exemplifies the "if we build it, they will come" fallacy applied to regulation. This view of regulation and competition holds that deregulation in a market with a small amount of rivalry or competition will induce more competition. In fact, economics shows that deregulation in this case may lead instead to a unconstrained oligopoly.

Thus, this provision of the bill can be applied in such a way as to lead to less competition and higher prices, a perverse result. For example, if the FERC decides that three pipeline suppliers for an LDC constitutes a "workably competitive" market, the deregulation of the lowest cost pipeline could cause its prices to rise to meet the level of the next higher priced pipeline. The result would be to award the lowest cost pipeline with higher-than-market return, yet do nothing to improve efficiency or, equivalently, reduce costs.

It would be far preferable if the legislation contained specific indicia of what constitutes competition sufficient to justify deregulation. In the alternative, the legislation might require the FERC to determine that deregulation would yield prices which are not higher than prices that would obtain under regulation, measured as the level of earned return.

IV The legislation unfairly targets federal and state regulation as the source of the natural gas industry's failure to sell all the gas it can produce. Instead, regulation is an essential component of an industry which is competitive only partially and only in certain portions of the market.

In several sections the bill blames regulation for some of the perceived problems of the natural gas industry. Section 1001 -- Findings states that the "regulatory and statutory structure has imposed burdens which have resulted in a decline of natural gas consumption, which is contrary to the national interest." Section 1002 -- Purposes promises to improve the situation of the natural gas industry by "removing or revising burdensome regulatory and statutory provisions which create disincentives to competition." This same section states that the bill will correct the "lack of financial incentives to pursue high-risk gas transportation projects." Finally, Section 1032 -- Removal of State and Local Barriers promises to identify state and locally imposed regulatory barriers to increased national natural gas usage.

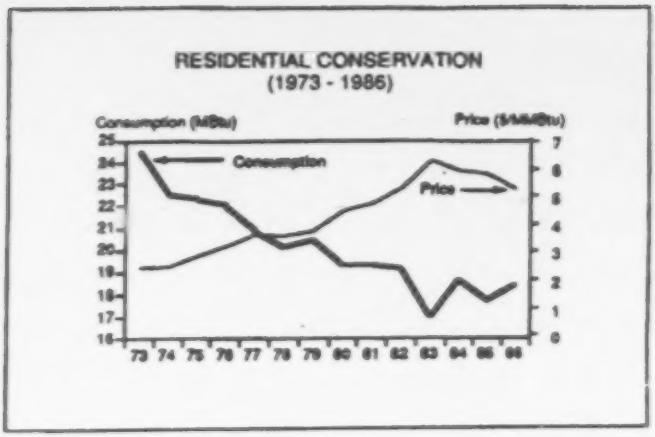
NASUCA has several comments about these criticisms of federal, state and local regulation. First, we agree that regulation should not be burdensome. In testimony before the Subcommittee on Environment, Energy and Natural Resources of the House Committee on Government Operations, NASUCA Gas Committee Chair Margaret Ann Samuels testified:

> A major detriment to consumer advocates and the consumers they represent is the sometimes interminable delays in the FERC decisionmaking process.

We noted with interest Section 1017 of the legislation which establishes a maximum period in which the FERC must take action on an application for rehearing. We are aware of similar provisions in other energy legislation introduced in Congress and will be considering which, if any, such provision to support. NASUCA members will likely consider a resolution on the subject at our upcoming national meeting.

Continued efficient regulation of the natural gas industry is critical to the welfare of the clients NASUCA members represent. In short, the natural gas industry is not, or should not be, a candidate for full deregulation.

We seriously doubt the assertion that federal regulation has acted to curtail the use of natural gas in the United States. Instead, the substantial price increases for natural gas supply beginning in 1973 have caused residential consumers to use natural gas more wisely, practicing conservation, especially for domestic heating with natural gas. In fact, it is more accurate to say that deregulation of wellhead prices, not regulation of pipelines has lead to conservation in the residential and small commercial sector. This trend is dramatically illustrated in data presented by the American Gas Association in Columbus, Ohio on April 1, 1991. The data show that residential natural gas consumption fell 27% from 1973-1989. (Commercial gas consumption fell 21% during the same period.) The following graph compares residential consumption in the period 1973-1986 with the average price of natural gas:



Source: Presentation of Rich Ittenag, American Gas Association, 4/1/91, Columbus, Ohio

It is especially ironic that, after inducing conservation with higher prices for natural gas, the natural gas industry now wants to shift further costs to these same consumers in an effort to stimulate new demand for natural gas. In that sense, residential customers will pay higher prices twice: once causing them to conserve, once because they did conserve.

Concerning incentives to undertake risky pipeline ventures, we observe that it should not be necessary to place all natural gas consumers at risk to finance such projects. As discussed at length previously in this testimony, many features of this bill shift risk and revenue requirements onto those customers with the least ability to react to higher prices. It is manifestly unfair to use these consumers as a "cash cow" to finance risky projects. Nor is it necessary to raise the profit level or rate of return for all the business a pipeline does to

induce the company to undertake new projects.

One measure of the success of regulation is whether it yields prices consistent with what a free market would yield. Prices are fair and efficient if the profit level or rate of return a market participant is able to earn is equal to a market return. As the economist Joseph Schumpeter showed, a firm can consistently exceed the average market return only through the exercise of market power. All other divergences from a normal market return are temporary and are due to innovation or entrepreneurship.

In fact, it is necessary for the functioning of a competitive market (or an efficiently regulated industry) that profits not be allowed to consistently exceed a normal level. Consider the following insight of J. M. Clark:

> In light of what we want competition to do for us, what are the features it needs to have which are implied in these objectives?
>
> * * *
>
> A second group of objectives is concerned with the diffusion of the benefits of progress, to customers in lower prices or to those who contribute factors of production... The diffusion is wanted for its own sake, but it also has a special role in the incentives to progress. What it means is that a renewal of differential profits can be had only by renewed innovation... This role would be vitiated if the diffusion were instantaneous and complete, since then the innovation would bring no rewards to the innovator. The dynamic system is not one of elimination of profits, but one of erosion and re-creation, both of which are jointly essential.[1]

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[1]Clark, J.M., "Competition: Static Models and Dynamic Aspects," American Economic Review 45 (May 1955): 453-454 (emphasis added)

V **The bill insulates pipeline companies both from true competition and from its surrogate, cost-of-service regulation. Through the combination of its provisions, the bill will create a natural gas pipeline industry which can achieve super-normal profits without actually undertaking any new projects, becoming more efficient or increasing the use of natural gas.**

Higher profits for the natural gas industry will not necessarily achieve the goals set forth in this legislation. There is no necessary connection between higher profits and any special purposes for which the firm may use those profits. Two examples will suffice. Mobil Oil reacted to the higher profits which accompanied the decontrol of oil prices not by drilling for more oil, but by buying Montgomery Wards. Similarly, higher profits in the telecommunications industry are going into a variety of diversified investments. Meanwhile, many state regulators are becoming concerned about a decline in service quality of local exchange telephone service.

If the intention of this bill is to reward risky pipeline investments with high returns, much more careful targeting of that effect is needed. Otherwise, NASUCA predicts that the only major effect of this legislation will be to increase the bills for residential gas customers and increase the profits of regulated pipeline companies.

1989-22

THE NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES

RESOLUTION

Resolving That The Federal Energy Regulatory Commission Should Return To The Legal And Equitable Principles Of The Natural Gas Act And Rely On Evidence Of Actual Cost In Its Rate Design Decisions

WHEREAS, The Federal Energy Regulatory Commission (FERC) in May, 1989 issued a policy statement in docket No. PL89-2 regarding rate design elements which it recommended in order to achieve its announced goals of maximizing throughput and rationing peak capacity on interstate gas pipelines::

WHEREAS, FERC's policy goal of rationing peak capacity by price to those who value it the most will shift costs from gas transportation users and result in higher costs to captive heating consumers who need gas on the coldest days;

WHEREAS, Rates for natural gas service are to be based on the cost of providing service, pursuant to the Natural Gas Act of 1938;

WHEREAS, The cost of providing gas service during peak periods has not been shown to be substantially higher than at other times;

WHEREAS, FERC's policy statement provides no legal basis for its departure from cost-of-service principles to adoption of value of service pricing;

WHEREAS, Encouraging maximum usage of gas by fostering throughput to the fullest extent possible fails to encourage economic usage of a valuable resource, primarily benefits gas producers and would result in higher gas prices by depleting the excess gas supply at a faster rate;

WHEREAS, FERC's proposal for seasonal rates which is intended to increase summer gas usage and shift costs to heating customers cannot be justified based upon pipeline capacity constraints since these constraints often occur at times other than in coldest weather;

WHEREAS, The purpose of natural gas regulation has been declared by the U.S. Supreme Court to be to protect consumers from excessive prices;

WHEREAS, FERC staff and administrative law judges have been subjected to education sessions in order to supplant the evidentiary presentations and maximize the likelihood that decisions will reflect the economic theory of the rate design policy statement;

THEREFORE, BE IT RESOLVED that the National Association of State Utility Consumer Advocates (NASUCA) calls upon the Federal Energy Regulatory Commission to return to the NGA-mandated principles of cost-based rates and protection of ratepayers in setting rate design elements for gas pipeline companies;

BE IT FURTHER RESOLVED that NASUCA calls upon the FERC to consider whether increased gas usage is not an end to be achieved at all costs;

BE IT FURTHER RESOLVED that NASUCA urges the FERC to make rate design decisions in all cases based on the evidence presented without predetermination based on goals which are both inequitable and economically unsound.

BE IT FURTHER RESOLVED that NASUCA authorizes the Executive Committee to develop positions and take further actions consistent with the contents of this resolution. The Executive Committee shall inform the membership of such positions and actions prior to proceeding with them, if at all possible. In any event, the Executive Committee will advise the membership of any actions taken consistent with the recommendations contained herein.

Approved by NASUCA:

Boston, MA

November 14, 1989
Date

Submitted and Favorably Reported by:

NASUCA Gas Committee

November 13, 1989
Date

Committee Members:
Margaret Ann Samuels (OH), Chairman
Craig Burgraff (PA)
Paul Buckley (MD)
James M. Burk (IN)
Mollie Glitsis (GA)
Joseph Ingles (UT)
Sandra Mattavous-Frye (DC)

1990 - 13

NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES

RESOLUTION

Opposing the Federal Energy Regulatory Commission's (FERC) Policies Allowing Waiver of Section 154.305(b)(1) of the Commission's Regulations and Allowing Flow Through in Pipeline PGA's of Producer Demand Charges on an As-Billed Basis

WHEREAS, NASUCA has supported the FERC's actions towards the creation of workably competitive gas markets as long as local distribution companies are provided with adequate flexibility in their purchasing decisions and are protected from abuses of monopoly power;

WHEREAS, the FERC's current regulations at Section 154.305(b)(1) require that the cost of a pipeline's purchases from producers be applied only to the commodity component of a pipeline's rates;

WHEREAS, the FERC has recently allowed waivers of Section 154.305(b)(1) of its regulations to allow pipelines to flow through, in their PGA's, demand charges from producers on an as-billed basis;

WHEREAS, the flow through of producer demand charges, on an as-billed basis, will shift risks associated with procurement of a marketable gas supply away from the pipeline and onto its customers;

WHEREAS, the flow through of producer demand charges on an as-billed basis will limit pipeline customers' purchasing flexibility and will inhibit the flow of market signals from the end-user back to the wellhead;

WHEREAS, the combined impact of the FERC's policy statement in favor of seasonal rates and the flow through of producer demand charges on an as-billed basis will be to drastically shift costs to heating customers in contravention of the purpose of natural gas regulation which is to protect consumers from excessive prices;

WHEREAS, the FERC's actions are particularly egregious where it has allowed the flow through of affiliated producer demand charges on an as-billed basis;

WHEREAS, the flow through of affiliated producer demand charges on an as-billed basis clearly provides ample opportunity for the abuse of monopoly power on the part of pipelines and their production affiliates;

THEREFORE, BE IT RESOLVED, that the National Association of State Utility Consumer Advocates (NASUCA) opposes the Federal Regulatory Commission's policies allowing for the flow through of producer demand charges on an as-billed basis.

BE IT FURTHER RESOLVED that NASUCA urges the FERC to, at a minimum, deny the flow through of affiliated demand charges on an as-billed basis.

BE IT FURTHER RESOLVED that NASUCA authorizes the Executive Committee to develop positions and take further actions consistent with the contents of this resolution. The Executive Committee shall inform the membership of such positions and actions prior to proceeding with them, if at all possible. In any event, the Executive Committee will advise the membership of any actions taken consistent with the recommendations contained herein.

Approved by NASUCA:

Orlando, Florida
Place

November 13, 1990
Date

Submitted by:

NASUCA Gas Committee

October 18, 1990
Date

Committee Members:
Margaret Ann Samuels (OH) Chairman
Craig Burgraff (PA)
Paul Buckley (MD)
Rafael Epstein (NY)
Byron Harris (WV)
Joseph Ingles (UT)
Bill Kowalski (CT)
Sandra Mattavous-Frye (DC)
Carl McIntosh (SC)

1990 - 14

NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES

RESOLUTION

Urging the Federal Energy Regulatory Commission (FERC) to Reverse its Position that Interstate Pipeline Companies are Entitled to Have Pre-Granted Authority to Abandon Firm Transportation Services Upon the Expiration of a Contract for that Service

WHEREAS, the issuance of Order No. 436, supported by the National Association of State Utility Consumer Advocates (NASUCA), marked the FERC's adoption of the goal of establishing workably competitive gas markets, primarily through the advent of "open access" transportation;

WHEREAS, one of the cornerstones of the open access policy is the right of firm sales customers to convert firm sales entitlements to firm transportation capacity rights, as detailed at Section 284.10 of the FERC's Regulations;

WHEREAS, the FERC and the U.S. Court of Appeals for the District of Columbia Circuit have concurred that the contract demand conversion right is critical if firm sales customers are to participate in the open-access transportation program;

WHEREAS, Section 284.221(d) of the FERC's Regulations provides interstate pipeline companies with pre-granted authority to abandon firm transportation services upon the expiration of a contract for such services, even if the transportation services were conversions from firm sales contracts under Section 284.10(c) of the FERC's Regulations;

WHEREAS, Section 7(b) of the Natural Gas Act (NGA), which applies, inter alia, to traditional certificated firm sales services rendered by interstate pipeline companies, was to protect customers against abusive exercise of monopoly power by interstate pipeline companies;

WHEREAS, the right to fully exercise certificated firm transportation services without the threat of pre-granted abandonment is critical to the ability of firm customers to contract for reliable, long-term natural gas supplies;

WHEREAS, the U.S. Court of Appeals recently rejected the FERC's explanation for its policy of allowing pre-granted abandonment of transportation services and remanded the issue to FERC for reconsideration;

WHEREAS, the stated reason for the Court's decision is that pre-granted abandonment of firm transportation service is at odds with the NGA's goal of protecting firm gas customers from abusive exercise of monopoly power;

THEREFORE, BE IT RESOLVED that the National Association of State Utility Consumer Advocates (NASUCA) strongly urges the FERC to revise its policy embodied at Section 284.221(d) of its Regulations so that interstate pipeline companies do not have pre-granted authority to abandon firm transportation services upon expiration of a contract for that service.

BE IT FURTHER RESOLVED that NASUCA urges the FERC to take this action when it prepares a final rule in response to the U.S. Court of Appeals.

BE IT FURTHER RESOLVED that NASUCA authorizes the Executive Committee to develop positions and take further actions consistent with the contents of this resolution. The Executive Committee shall inform the membership of such positions and actions prior to proceeding with them, if at all possible. In any event, the Executive Committee will advise the membership of any actions taken consistent with the recommendations contained herein.

Approved by NASUCA:

Orlando, Florida
Place

November 13, 1990
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NASUCA Gas Committee

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Carl McIntosh

Senator WIRTH. Good, Mr. Binz. Thank you very much for being here. We would appreciate any thoughts that you and your association have on what the indices for effective competition ought to be. That is a problem which exists in just about every formerly regulated or about to be deregulated marketplace. We are looking at that right now in the cable television world. For example, the FCC is struggling with that right now, you know, what are the indices for effective competition, and we would appreciate any thoughts that you might have on how that might fit in the natural gas world.

The dilemma that we face, I think, was outlined in your testimony, and maybe you would give this some thought. How do you go about giving pipelines the incentive to expand markets? We want them to build new capacity, expand markets, use natural gas, back out of foreign oil? We would all agree with that as a set of, I would think, as a set of goals that makes sense.

How do you go about doing that and still protect consumers? We have thought that we tried to do that. I have always been a little bit skeptical. I think, if we look at the prices of natural gas and what has happened with natural gas, it is still, in my opinion, a remarkable bargain, and I am not sure that the sky fell in when a lot of natural gas prices were deregulated in the 1970's and 1980's, that there was an enormous increase in prices, as suspected by some consumer groups. But it is a very legitimate concern. And what our job is is to try to figure out what that balance is.

Mr. BINZ. A couple of things I have had quite a bit of time to think about it sitting on this front row seat. I read your comment in the Congressional Record, when you introduced this legislation, very carefully, and one of the things you noted was that your Jeep has a fuel cost approximately half. This is, I guess, this is ignoring the up-front cost of conversion——

Senator WIRTH. It costs about 50 cents a gallon.

Mr. BINZ. Fifty cents a gallon equivalent in gasoline prices. Notwithstanding what Mr. Yuhnke said on whether it is actually helping the greenhouse issue, it seems to me that natural gas is more than competitive on a price basis with gasoline. I mean, you yourself are saying that it is half the price of gasoline. It seems that the industry's problem there is probably gaining acceptability for use of the VNG. I question whether the additional cut in the costs of the—of natural gas for VNG is necessary to stimulated the use. I do not think that is the problem with that sector. That is one issue.

Senator WIRTH. I am not sure that is being suggested either, is it?

Mr. BINZ. Well, to the extent that residential customers are going to pay more for their natural gas, aiding both producers and pipelines to move more gas for new markets, including VNG, that will be a factor.

Senator WIRTH. And you are convinced that the two or three provisions in the legislation you referred to will, in fact, cause prices of natural gas to consumers to go up?

Mr. BINZ. I think it is indubitable with respect to a couple of them. When you start loading new costs in the producers' so-called storage costs the producers are referring to, that is going to drive up the demand charge passed on by pipelines to their purchase gas

adjustments, to PGAs, and in virtually every State jurisdiction, that cost goes directly to the bill of the firm customers.

Senator WIRTH. But what is wrong with Mr. Vessels' argument that says, in effect, you pay for what you get? That if, in fact, consumers of any kind, whether they are residential consumers or industrial consumers or commercial consumers, benefit from the fact that that gas is stored during the low demand time so that it is available at a high demand time, that therefore that storage ought to be paid for somewhere along the line. Why, as I understood what he was saying, is it that there is effectively a you-pay-for-what-you-get issue, which I think we are increasingly getting on all energy and environmental issues? We are trying to determine what the costs are so that people do pay for what they get.

Mr. BINZ. The natural gas producers have the problem of seasonable demand, no doubt about that. So does May D&F. May D&F probably has 40 percent of their sales between Thanksgiving and Christmas, but May D&F does not charge a membership charge to shop at May D&F to cover their fixed costs. That is an analogous situation with these producers. They may view it as storage. From the consumer side, it is simply "I'm not buying gas from you at this time of year. I'm buying it at different times." Depending on the marketplace——

Senator WIRTH. May D&F would argue that what happens, I would think, is that they have a sale and increase their volume very significantly and that, in turn, helps to keep the prices to consumers down.

Mr. BINZ. And the sale applies equally to all buyers.

Senator WIRTH. What the industry would argue here, I would think, would be that during the time when May D&F is out buying coats or hats or whatever it may be, we are storing that to ultimately help keep the coats and hats available and to keep the price down. That if you did not have that storage, there would be such competition for a limited amount of gas that the prices would go up very dramatically, and having a volume of gas available through storage in the summertime in effect keeps prices low. I would think it does work that way.

Mr. BINZ. Senator Wirth, my understanding of what they were saying by storage is simply not moving gas.

Senator WIRTH. Yes.

Mr. BINZ. It is not as if we have storage facilities to construct if the gas is not being sold at that time of year. Whether that actually entails a cost to those producers, I think, is the issue that the FERC is right now looking at, whether you can identify something comparable to fixed-cost facilities which ought to be recovered in a fixed-cost charge.

Senator WIRTH. Let me ask you if I might, any other thoughts that you might have on the protection-of-consumer issue, we would appreciate having.

Mr. BINZ. Sure. And, Senator Wirth, again, I think there are some places that we agree very closely with your thoughts on these matters. I did not want to come here today to defend the FERC, because our members just like——

Senator WIRTH. Not very many people do.

Mr. BINZ. It is not a popular activity. In fact, we were asked by this House subcommittee, I mentioned earlier, to provide comments. I think I should get those to your staff as well.

Senator WIRTH. Right.

Mr. BINZ. I expected you to ask me about the abolishment of FERC. We are looking at that issue ourselves to see, from a completely different perspective from the industry, whether the continuation of FERC——

Senator WIRTH. I understand the administration's frustration with FERC and their desire to move the furniture around. I myself tend to think that this presents a good forum for playing out a lot of the various groups, and I myself am reluctant to move it within a political structure where a different set of decisions might well be made. That is the problem I have.

Mr. BINZ. That is my personal view as well.

Senator WIRTH. But we will get to that at some point. Part of your comments might also address the issue, you know, if you drop prices so low, or you drop prices significantly, it seems to me you begin to cross a line where you are destroying incentives for production, and that this, in turn, then causes problems on deliverability, and that is a problem that we had in the 1970's. That was discussed earlier with, I think, Mr. Whitney. We discussed that set of problems. I mean, that is very real, is it not?

I mean, there is a balance in here that if prices drop too far, then you are going to have major deliverability problems, and when those occur, then prices spike back up again.

Mr. BINZ. Yes, Senator. I agree, and I think I speak for everyone in our association. We do not advocate prices which constrain supply. I think there was plenty of debate previous to 1978 and certainly between 1978 and 1985 where there was a price spike coming in 1985. I remember that debate. I think we are talking about marginal issues here which are not going to effect, in a gross fashion, deliverability of natural gas.

Our concern is if, for our customers, it goes from $1.30, say, to $1.40 in order for the industry to be able to first become considerably more profitable, and I think it will under that range, the section 1016, which discusses the use of a replacement cost for rate base as the upper bound of reasonableness of rates. I think that could cause that.

I do not think—I certainly hope, and I am sure our members would be committed to not discussing issues which demonstrably could lead to curtailment of delivery. I think we are well beyond that.

Senator WIRTH. Just a final question, if I might, and, Mr. Schroeder, you might react to this. I have been very interested in the reform of the Public Utility Holding Company and bringing competitive forces into the marketplace, if, in fact, you can do that without harming your basic utility structure.

Now, a pretty strong argument gets made that if, for example, in thinking about us here in the State of Colorado, the Public Utilities Commission requires, as I understand it, the Public Service Company to build its plant and to have, as a requirement, a certain percentage of equity, about 50-percent equity. And that is a pretty expensive proposition.

We all know that equity is significantly more expensive than debt. So the State of Colorado makes this requirement on the Public Service Company, or any utility in Colorado, that if they are going to build any increased power generation capability, it has to be on about a 50-50 debt-equity ratio. That is done by regulation.

If we were to reform the Public Utility Holding Company Act—Mr. Schroeder, you are a lot more familiar with this than I am—if we were to reform the Public Utility Company Holding Act and, in fact, what we would be doing is encouraging a company, say, like PG&E to come in and, if there were, which there is not now, but if there were a demand for increased power now and there was competition for building a new power plant, PG&E could come in with its separate subsidiary into the State of Colorado and build that power plant using, say, maybe 5-percent or 10-percent equity, 90-percent to 95-percent debt, and build even an identical power plant significantly cheaper than the Public Service Company could do so.

So therefore by reforming the Public Utility Holding Company Act and not making changes related to the regulatory structure in Colorado, what we, in effect, would be doing in the Congress is inviting non-Colorado power groups to come in and compete for production of power in the State.

Now, that may or may not be a good thing to do, but I think at a time in which we are concerned here about control of our own destiny, maybe that is not a smart thing to do, to be encouraging those kinds of outside groups to come in.

Now, if that is a fair description of the problem, how do you solve that problem? One choice is, do not reform the Public Utility Holding Company Act. Another one is to what? What is the fill-in-the-blank? Rather than saying no to reforming the Public Utility Holding Company Act, what do you do in terms of the regulatory structure here? Should there be changes in the debt/equity structure of the State public utility? Do we just depend upon the PUC to do that? You are familiar with this problem I know, Mr. Schroeder.

Mr. SCHROEDER. Yes, Mr. Chairman. I think that reforming the Public Utility Holding Company Act to allow these independent power producers to come in is going to—the reform at the Federal level will drive some reform and change at the State level.

Public Service Company of Colorado, or any other investor-owned utility, is going to advise their commission that they are unable to compete in that power generation market. They will presumably seek either the flexibility to do that or go out and purchase the cheaper power, which the consumer would certainly benefit from.

At some point, as you know, there is a risk that you end up getting power supplied by people that are too highly leveraged and are too risky. Those, again, are decisions that the purchasers of that power, the regulated utility, will be judged on by the Public Utility Commission. Did you make a prudent decision? Did you backstop your power-purchasing decisions with reliable suppliers or reliable alternatives if your highly leveraged source should fail?

Those are decisions that are made, you know, every day in the market in other areas in terms of committing to supply and choosing among cheaper alternatives that may be arguably less reliable. And those are decisions that I think ultimately get made more efficiently by the market than by the regulators saying debt/equity.

Senator WIRTH. Fine. Then how do you make that decision if, in fact, you are a regulated utility where you are not dealing with the marketplace, you are effectively dealing with a situation where the State PUC is intervening in that marketplace and what might be in this situation an inefficient fashion? What is the solution to that? Assume that the State regulatory commission is going to change and adapt itself to the new rules? Is that the solution?

Mr. SCHROEDER. I think that is the likely outcome, and I think the State public utility commissions and the commissioners are a well-versed group of people that understand the market dynamics and will respond and recognize that they have disadvantaged the regulated utility.

Senator WIRTH. That is the argument you would make, the reform the administration would make. Reform the Public Utility Act and assume that the State regulators would be flexible. What would be your answer to that, Mr. Binz?

Mr. BINZ. I would like to just build on what. Mr. Schroeder was saying. I think, Senator Wirth, you correctly point out that one result you may get is very highly leveraged projects either by utility affiliates or by true independent power producers.

So I think when we look at the administration's PUHCA book of reform or that of Senator Johnston's bill, I think what we ought to be looking at is whether we want a future of relatively highly leveraged independent power projects producing the main new sources of electric power.

There is a reason why State public utilities commissions and regulators generally and the SEC looks at those issues, and that is that we do not want this to be a highly competitive market who may or may not be there when you want it. This is a public good. This is a public utility service. We want security, which is provided in large part, it seems to me, by the requirement of equity involvement in these projects.

Senator WIRTH. Is there any history that we can learn from? For example, what is the history of people in the cogeneration business?

Mr. BINZ. It is spotty.

Senator WIRTH. I would guess they have been highly leveraged.

Mr. BINZ. Yes, and I think you will find it spotty.

Senator WIRTH. And their reliability has been spotty?

Mr. BINZ. I cannot speak so much of their systems-delivered reliability. In terms of their projects being able to hang in there, I think it is spotty.

Senator WIRTH. So that would argue that that kind of high leverage is not a good idea, right?

Mr. BINZ. I think it is self-evident. High leverage is going to require higher returns because the risk is greater and, you know, we do not have to look to many other industries to find industries who have gone that route.

Senator WIRTH. And so, therefore, in the deliberations on the Public Utility Holding Company Act, is there a floor that gets put in there in terms of what is an acceptable amount of leverage and what is not? I am reluctant to get into that sort of thing, for us to be intervening in the marketplace, saying this is acceptable, this is not acceptable. I am not sure that that is a congressional subject.

Mr. SCHROEDER. I agree. And on the cogeneration projects, I think allegations were made at the beginning, shortly after PURPA became law, that these were not going to be reliable suppliers. I think experience has indicated that they are far more reliable than the initial allegations suggested.

You have some utilities that rely on that for substantial amount of their power. I do not know what the statistics are, and maybe Mr. Binz does. One reason why cogeneration may be less reliable is that you are dealing, in some cases, with some of the more exotic technologies. They are not just baseload plants.

They are dealing with unique fuels or unique technologies, but a lot of people, I think, are in a position to rely on cogenerated power for a substantial amount of their market load. I do not know that necessarily debt-equity ratio is the determinative criteria on their performance.

Mr. BINZ. Senator Wirth, I would like to take you up on your question and like to answer it in a length of time. My association has a couple of resolutions on PUHCA reform. I think it is also fair to say we are going to be debating it at our next meeting.

Senator WIRTH. We look forward to hearing from you. As you know, I hope it happens before May because I think the train is moving pretty rapidly in terms of markup on this issue, and I hope it is. I think there are some very interesting issues; it is not what it seems. And there are potentially, there seem to be some unintended consequences in here that we have to really be aware of. Do you end up with a less reliable operation? Do you end up making yourself vulnerable to large groups from outside, you know, coming in and taking over or having undue amounts of influence? And what are the impacts long term on the consumer, though maybe in the short term it looks like there are going to be lower rates, but in long term if you have failures, you have higher rates. And there are a number of unintended consequences than have to be sorted through.

Mr. SCHROEDER. I think some of these similar arguments were made when they unbundled the natural gas transportation and merchant activities. They argued that it would be unreliable to just rely on transportation and have to go get your own gas supply, and yet we have not seen that problem.

Senator WIRTH. We have the same arguments in the deregulations of the telephone industry, in which I sat through and listened to almost identical arguments. If you substitute telecommunications-telephone for natural gas, the parallels are very significant, but still very real issues. I think Mr. Binz brought up some of those talking about bypass and access charges and so on. It gets very complicated.

Anyway, both of you, thank you very much for being here. We greatly appreciate it. To all of our participants this morning, we appreciate it. We made a very good record, I think, on an extremely interesting and important issue for the country and for Colorado. Thank you very much.

[Whereupon, at 12:10 p.m., the hearing was adjourned.]

APPENDIX

ADDITIONAL MATERIAL SUBMITTED FOR THE RECORD

Reducing Greenhouse Gas Emissions
With Alternative Transportation Fuels

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EXECUTIVE SUMMARY

Accumulation of heat-trapping, or "greenhouse" gases (GHGs) is expected to warm the Earth by 2 to 4 °C by the middle of the next century, leading to widespread and potentially catastrophic impacts on the Earth's environment. In the United States, the transportation sector produces 30% of the annual emissions of the main GHG, carbon dioxide (CO_2), and contributes to emissions of methane (CH_4), nitrous oxide (N_2O), and tropospheric (ground level) ozone.

Alternative transportation fuels have the potential to increase or decrease GHG emissions relative to gasoline. There is currently a high level of interest in alternative fuels because of their air quality and energy security benefits; however, their GHG impact has to date not been a major factor in the development of strategies to promote their use. Thus, a major opportunity to decrease GHG emissions from the transportation sector could be missed. Even worse, some alternative fuel choices could cause GHG emissions from transportation to increase. We propose that the GHG impact be included in the decision-making process, and that mechanisms be established to encourage auto-makers and fuel manufacturers to develop fuels which will lead to reduced GHG impacts relative to gasoline.

Here, we review estimates of the total life-cycle GHG emissions from fuel options that we consider to be near-term options because they are already in use as motor vehicle fuels and/or are being promoted for wider use by economically viable "sponsors". These options include methanol derived from coal (methanol/coal), natural gas (methanol/NG), or biomass, compressed natural gas used directly as a fuel (CNG), ethanol from biomass and electricity generated from a variety of sources. We discuss the potential availability of each fuel and how supply constraints may limit its use. We do

not consider other potentially attractive options such as fuel cells and hydrogen because they do not appear to be readily available options in the near term. However, we believe they may become preferable options in the longer term.

The life-cycle analyses that we reviewed considered GHG emissions of CH_4 and N_2O as well as CO_2. To calculate the total GHG impact, it is necessary to convert these other GHGs to "CO_2 equivalents". We used factors of 20 and 200, respectively, to convert tons of CH_4 or N_2O to tons of "CO_2".

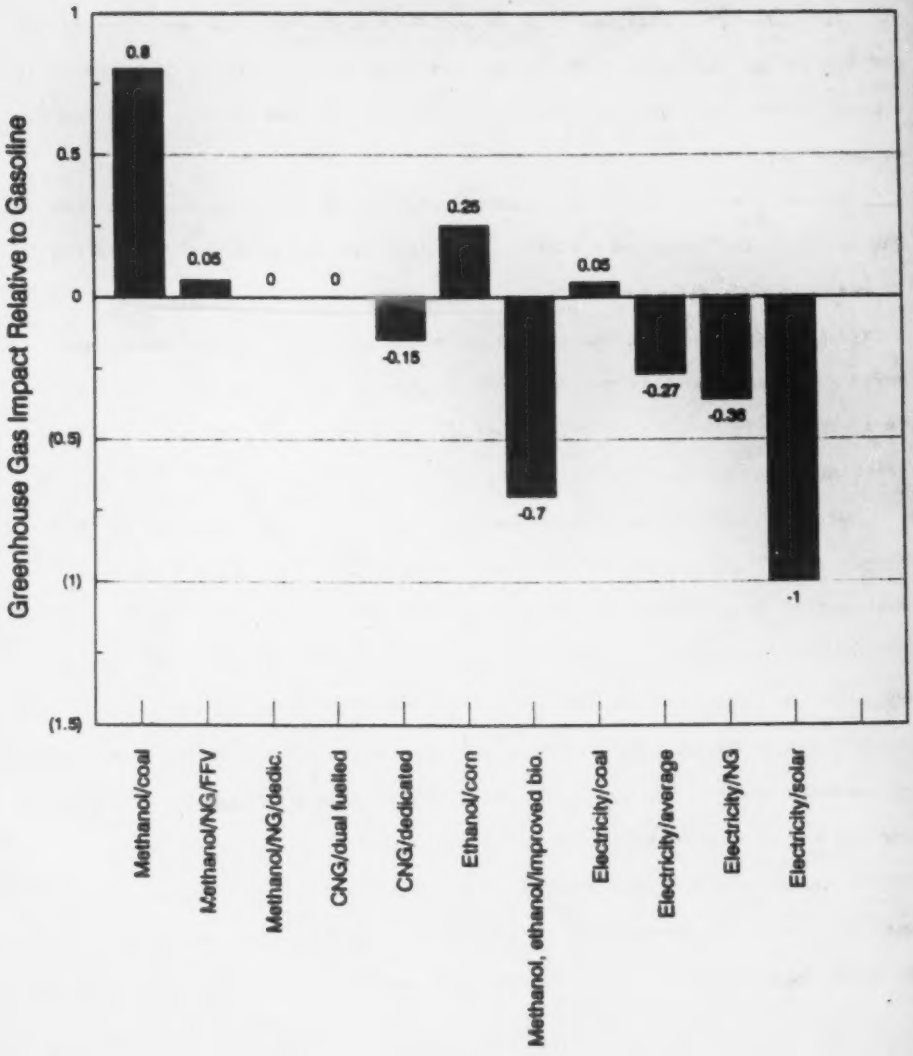
Figure 1 summarizes best estimates of the GHG impact of each alternative. The array of fuel options exhibit a wide range of GHG impacts, from an 80% increase in GHGs from methanol/coal compared to gasoline, to virtual elimination of GHG emissions from solar electricity. These estimates are based on a "snapshot" of current technologies or predictions for the near term; the relative impacts may change as the technology advances or as the gasoline base case changes in the future.

Of the fossil-based alternatives (methanol/coal, methanol/NG, or CNG), only methanol/coal shows a significant GHG detriment, of about +80%. Methanol/NG gives GHG emissions roughly equivalent to gasoline (0%), with slightly higher GHG emissions (+5%) expected from flexible-fuelled vehicles compared to a dedicated methanol vehicle. The GHG impact of compressed natural gas (CNG) as a vehicle fuel is expected to range from no change (0%) to somewhat better than gasoline (-15%), again depending largely on whether or not the vehicle is optimized for performance on the alternative fuel.

Although CNG produces somewhat lower GHG emissions on average than methanol, this is dependant on vehicle technology. A gasoline engine modified to operate as a dual-fuelled CNG vehicle will likely compromise in

Figure 1

Greenhouse Gas Impact of Alternative Fuels
(light duty vehicles)



fuel efficiency in order to operate on both the gaseous and liquid fuels and will have relatively high tailpipe methane emissions. Such a vehicle could have a higher GHG impact than a vehicle designed to maximize fuel efficiencies. A well designed methanol vehicle could have a lower GHG impact than a dual-fuelled CNG vehicle, but a well designed, dedicated CNG vehicle will likely have a lower impact than its methanol counterpart because of the inherent differences in the fuel.

Improvements in vehicles or increased efficiency in the fuel cycle could significantly lower the GHG impact of fossil-based alternatives relative to gasoline; reductions of 20% or more vs. gasoline may be attainable.

Biomass-based fuels (methanol, ethanol or other fuels derived from plants and other biomaterials) have the potential for very large GHG reductions relative to gasoline (-70%). Unfortunately, the only biofuel currently being used in the U.S. transportation sector, corn ethanol, falls far short of this potential, with a net GHG impact about 25% greater than gasoline. This results from a combination of high fossil fuel inputs to raise and process the corn, and high levels of nitrogen fertilization.

The two most critical factor determining the GHG impact of electric vehicles (EVs) are the efficiency of the vehicle and the fuel used to generate the electricity. EVs with mid range efficiencies (2.6 mi/kWH) would yield a GHG reduction on any electricity source other than 100% coal; the latter would give a slight GHG detriment (+5%). Operation on electricity from non-carbon dioxide emitting sources such as solar energy could potentially result in almost complete elimination of GHG emissions (-100%).

Feedstock availability and other constraints make it unlikely that any one fuel could displace motor gasoline within the next twenty years. Electric

vehicles will be limited to no more than about 17% of all vehicle miles travelled unless their limited driving range (currently about 85 miles between recharging, with industry projecting a 150 mile range by the late 1990s) can be increased. Biomass fuels will be limited to about 10 to 20% penetration by availability of land to grow energy crops. This may be increased (about another 5 to 40%) by development of processes to make biofuels from waste materials. CNG will be limited by availability of North American natural gas, which could supply about 13% of year 2010 motor gasoline consumption. Methanol is less constrained by feedstock considerations than other options, since it could be made from remote natural gas and then shipped to the U.S. as a liquid. Methanol can also be made from coal, which the U.S. has in great abundance; however, unless major changes are made in the coal to methanol process (e.g. CO_2 collection and disposal), this would have an unacceptable GHG impact.

Major improvements are likely in the fuel cycles and vehicle technologies of all of the alternatives, changing the GHG impacts in ways which will not be entirely predictable. We therefore do not believe that it is advisable at this time to designate any one fuel as the "best". Rather, we recommend that mechanisms be developed to give incentives to vehicle manufacturers and fuel producers to reduce the GHG impact (and other environmental impacts) of each fuel as much as possible. A competition between fuels based on their environmental benefits is the surest way to achieve the full potential offered by alternative fuels.

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Reducing Greenhouse Gas Emissions with Alternative Transportation Fuels

I. Introduction

Carbon dioxide and other heat-trapping or "greenhouse" gases (GHGs) are currently accumulating in the Earth's atmosphere. Scientists predict that this accumulation of gases will lead to an increase of 2 to 4°C in global average temperatures by the middle of the next century, with major and potentially catastrophic consequences for the Earth's environment (IPCC 1990). The transportation sector contributes significantly to the accumulation of carbon dioxide and other GHGs. The U.S. transportation sector as a whole is responsible for about 400 MTC (million metric tons of carbon) of CO_2 or about 30% of annual U.S. CO_2 emissions. Transportation is the fastest growing source sector for CO_2 emissions in the U.S. It also contributes to emissions of other GHGs, including CH_4 and N_2O.

Alternative fuels have the potential to either decrease or increase overall GHG emissions from the transportation sector, depending on which fuels are used, the process used to make the fuel, and the vehicle technology. In this report, we examine the potential GHG emission reductions which could be achieved in the transportation sector if the promotion of low-GHG emitting alternatives were adopted as a GHG reduction strategy. We will focus on displacement of the 18 quads of fuel consumed in highway transportation and especially the 13 quads of motor gasoline consumed per year, which is projected to increase to 15 quads/year by 2010. As a GHG reduction strategy it makes sense to target alternative motor gasoline because substitution of diesel fuel is not beneficial in terms of GHG reduction[1].

[1] See Unnasch et al. (1989) or DeLuchi (1990a) for a discussion of the GHG impact of alternatives to diesel fuel.

The use of alternative transportation fuels will have other environmental impacts, both positive and negative, in addition to their impact on GHG emissions. Most of the alternatives discussed here offer reductions in emissions of some or all of the pollutants which contribute to urban smog. On the other hand, there are potentially negative impacts such as increased nitrogen runoff and pesticide use from the production of energy crops for biomass fuels. We do not consider these impacts here; however they should be taken into consideration in making decisions about alternative fuel use.

In addition to offering environmental benefits, the use of alternative fuels could also increase U.S. energy security. The U.S. consumed 34 quads (1 quad = 10^{15} B.T.U.) of oil in 1988, 63% of this in the transportation sector, where 97% of all energy is provided by petroleum based fuels (EIA 1989). Currently, 42% of petroleum consumed in the U.S. is imported. Imports of oil have been rising and domestic production falling since the early 1980s. Much of our oil is imported from politically unstable regions of the world. Approximately half of U.S. petroleum imports come from the Organization of Petroleum Exporting Countries (OPEC), with half of this, or about 25%, coming from nations in the Mid East (EIA 1989). Diversifying the fuel supply in the U.S. transportation sector would make the U.S. economy less vulnerable to disruption by political instability in oil-producing nations, especially if alternatives can be supplied by domestic resources.

In section II we review and summarize previous analyses of the overall GHG impact of methanol, ethanol, natural gas, and electricity derived from a variety of feedstocks. This determines the possible GHG reduction per vehicle. In section III we examine feedstock availability and other factors which will limit the total amount of each fuel that can be produced. Taken

together, the GHG reduction per vehicle and the total amount of gasoline displaced by the fuel will determine the possible reduction of GHG emissions from that fuel (e.g. if a fuel which produces 50% less GHGs than gasoline per vehicle displaces 10% of all motor gasoline consumption, this reduces GHG emissions from motor gasoline by 5% overall). In section IV we examine some limiting cases of the potential reductions which each fuel offers. Section V contains our conclusions.

II. Greenhouse gas emissions from alternative fuels

In this section, we review previous analyses of the GHG emissions from natural gas, methanol derived from coal or natural gas, ethanol or methanol derived from biomass, and electricity as vehicle fuels. The options we chose to review are those for which we believe there is the possibility of significant penetration into the vehicle market in the next twenty or so years. We exclude consideration of vehicles which have fuel cell technology because fuel cells for vehicular applications are still in the early phase of research and development (Fisher 1990, Lehman et al. 1989). Hydrogen was excluded because we expect it to be prohibitively expensive in the near term (Fisher 1990, Harvey 1990), although eventually the cost may decrease sufficiently to make this an attractive option, with many of the same advantages and disadvantages as discussed below for electric vehicles. We exclude liquefied petroleum gas (LPG) because the supply is relatively limited and its production is in large part linked to oil and natural gas production.

It should be noted that the studies which we review below compare vehicles in which only the fuel is changed, without making the further changes in the vehicles which would be required to achieve equivalent performance

characteristics to a gasoline vehicle[2].

All the studies we examined base their comparison to base case life-cycle GHG emissions for gasoline as it is manufactured today. Changes in the gasoline production process can be expected in the future. It is difficult to predict the exact nature of these changes, which could increase or decrease the overall GHG impact of gasoline. For example, reformulated gasoline may have a lower carbon content, which would tend to decrease its GHG impact, but on the other hand it may take more process energy to produce, which would increase the GHG impact.

We discuss fossil-based alternatives in subsection A, biomass fuels in subsection B, and electricity in subsection C.

A. Fossil-based fuels

Several analyses (DeLuchi 1990a, DeLuchi 1990b, DeLuchi et al. 1987, Gushee 1988, Ho and Renner 1990, Unnasch et al. 1989) have examined the lifecycle GHG emissions of fossil-based fuels, including gasoline, natural gas, methanol manufactured from natural gas, and methanol from coal. We will discuss three of these analyses (DeLuchi 1990b, Ho and Renner 1990, and Unnasch et al. 1989) in more detail[3].

Table I summarizes some of the underlying assumptions in each of the three studies. Factors which most strongly influence the calculated GHG

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[2] Depending on the application, it may not always be necessary for the alternative vehicle to have performance characteristics identical to gasoline vehicles. For example, vehicles with shorter driving range (distance travelled between refuelling) can be targeted for fleet applications or as second vehicles in two-car homes.

[3] The analysis by Gushee (1988) only examines CO_2 emissions, and DeLuchi et al. (1987) and DeLuchi (1990a) contain less detailed and complete calculations than DeLuchi (1990b). DeLuchi (1990b) is a draft report which has recently been revised. Some of the estimates have changed, but not enough to alter the conclusions drawn here.

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Table I

Assumptions Used in GHG Emissions Estimates

From Fossil-Based Alternative Fuels

Parameter	DeLuchi 1990b	Unnasch et al. 1990	Ho and Steiner 1990 current	Ho and Steiner 1990 advanced
Gasoline				
Vehicular emissions				
--CH_4 g/mi	0.1	0.04	0.1	0.08
--N_2O g/mi	0.07	0.13	0.2	0.1
--CO g/mi	8.8	--	--	--
Fuel efficiency, mpg	20	27.5	20	25
Natural Gas				
Vehicular emissions				
--CH_4 g/mi	1.4(0.7-3.1)	0.68-1.2	1.0	1.0
--N_2O g/mi	0.07	0.13	0.3	0.1
--CO g/mi	0.2	--	--	--
Relative efficiency	1.06	1.00	1.00	1.10
NG compression energy	5%	2.7-11.6%	10%	10%
NG losses in transmission distrib, feedstock recov.	0.8%	0	1.5%	0.5%
Total NG fuel cycle "efficiency"	86% (LHV 74%)	78%	76%	81%
Methanol				
Vehicular emissions				
-- CH_4 g/mi	0.08	0.03	0.1	0.0
-- N_2O g/mi	0.07	0.11	0.2	0.1
-- CO g/mi	9.60	--	--	--
Relative efficiency	1.15	1.06	1.00	1.15
MS conversion efficiency	65%	67 to 74%	67%	72%
Coal conversion efficiency	56%	46 to 63%	54%	62%
All Fuels				
Conversion factors, mass/mass				
--CH_4 to CO_2	20 (10-40)	28 (83)	50	10
--N_2O to CO_2	200	300	300	290

impact of natural gas vehicles (NGVs) include the assumed thermal efficiency of an NGV relative to a gasoline vehicle, tailpipe emissions of CH_4 and N_2O, losses of natural gas from the distribution system and the conversion factor used to convert CH_4 or N_2O to "CO_2 equivalents". Both the thermal efficiency and tailpipe methane emissions may differ depending on whether the NGVs are dedicated or dual-fuelled vehicles[4].

Table II compares in detail the emissions estimates derived in the three studies. Table III-A summarizes these estimates. Some of the difference in estimates results from the use of different "conversion" factors for expressing CH_4 and N_2O emissions as CO_2 "equivalents". A recent publication has examined the question of the appropriate conversion factors in some detail (Lashof and Ahuja 1990). Earlier estimates of the relative warming impact of CH_4 vs. CO_2 looked only at the effect of a given concentration of each gas in the atmosphere. When this is done, it appears that a ton of atmospheric CH_4 has as much as 80 times the warming effect of a ton of CO_2. However, since CH_4 has a much shorter atmospheric lifetime than CO_2, the impact of a given amount of emitted CH_4 diminishes over time relative to a given amount of emitted CO_2. If one compares the impact of CH_4 vs. CO_2 over the course of 500 years, the relative warming impact on a mass basis is 10. If the comparison is cut off at 100 years, the impact of CH_4 is 20 times that of CO_2. Although some have suggested using an even shorter time period for the comparison, we do not believe this is appropriate for a long term environmental effect such

[4] We use "dual-fuelled vehicle" to mean a vehicle with two separate on-board storage systems for two separate fuels (here natural gas and gasoline), which are then used by the same engine. We use "flexible-fuelled vehicle" or FFV to mean a vehicle in which two fuels (here methanol and gasoline) can be mixed together in any ratio in the fuel storage tank and used together in the vehicle engine.

Table II: Comparison of Greenhouse Gas Emission Estimates of Fossil-Derived Alternative Fuels by Several Authors (values are CO_2 equivalents in grams per mile)[5]

	DeLuchi 1990b	Unnasch et al. 1989	Ho and Hansen 1990 advanced	Ho and Hansen 1990 current
Gasoline:				
Vehicle CO_2		311	254	306
" CH_4		1 (0.04)	1 (0.08)	5 (0.1)
" N_2O		36 (0.12)	20 (0.1)	60 (0.2)
Vehicle total	319	348	274	371
Fuel cycle CO_2		91	69	99
" CH_4		25 (0.88)	2 (0.3)	12 (0.24)
" N_2O		2 (0.0064)	1 (0.007)	2 (0.007)
Fuel cycle total	75	108	91	84
Gasoline total	394	456	325	481
Natural Gas:				
Vehicle CO_2		297	175	234
" CH_4		13-34 (0.65-1.2)	13 (1.5)	95 (1.9)
" N_2O		36 (0.12)	20 (0.1)	90 (0.3)
Vehicle total	250	311-327	210	417
Fuel cycle CO_2		43-72	53	100
" CH_4		2 (0.06)	6 (0.63)	83 (1.68)
" N_2O		2 (0.006)	1 (0.007)	2 (0.007)
Fuel cycle total	91	46-76	66	193
Natural gas total	350	357-403	276	610
Methanol:				
Vehicle CO_2		288	209	290
" CH_4		1 (0.03)	1 (0.08)	5 (0.1)
" N_2O		33 (0.11)	20 (0.1)	60 (0.2)
Vehicle total	254	323	230	355
Fuel cycle (gas) CO_2		84-129	73	135
" CH_4		3 (0.10)	6 (0.59)	59 (1.15)
" N_2O		2 (0.006)	1 (0.007)	2 (0.007)
Fuel cycle total	135	91-146	80	196
Methanol/NG total	389	414-469	310	550
Fuel cycle (coal) CO_2		433-541	325	560
" CH_4		0 (0.3)	3 (0.3)	15 (0.3)
" N_2O		0 (0)	28 (0.14)	42 (0.14)
Fuel cycle total	468	441-550	356	617
Methanol/coal total	709	764-873	586	972

[5] Values in parentheses are CH_4 or N_2O before conversion to CO_2 "equivalents". The conversion is done with the authors' conversion factor (see Table I).

Table III-A
Summary of GHG Emission Estimates of Fossil-Derived Alternative Fuels

Fuel	DeLuchi 1990b	Unnasch 1989	Ho and Renner "current"	Ho and Renner "advanced"
Gasoline	394	456	455	325
Natural Gas	350 -11%	357 to 403 -22% to -12%	610 +34%	276 -15%
Methanol/NG	389 -1%	414 to 469 -9% to +3%	550 +21%	310 -5%
Methanol/coal	709 +80%	691 to 790 +51% to +73%	972 +113%	586 +80%

Table III-B
GHG Emission Estimates, Adjusted[6]

Fuel	DeLuchi 1990b	Unnasch 1989	Ho and Renner "current"	Ho and Renner "advanced"
Gasoline	394	401	410	328
Natural Gas	350 -11%	314 to 352 -22% to -12%	461 +12%	298 -9%
Methanol/NG	389 -1%	369 to 410 -8% to +2%	475 +16%	317 -3%
Methanol/coal	709 +80%	691 to 790 +72% to +97%	897 +119%	590 +80%

[6] In this table, the estimates of the three authors are adjusted to all use the same GHG conversion factors of 20 (mass basis) for CH_4 to CO_2 and 200 for N_2O to CO_2. All are also adjusted to a gasoline fuel efficiency of 30 mpg except Ho and Renner's "advanced" case, which is based on a gasoline fuel efficiency of 35 mpg.

as global warming. We therefore use a CH_4 to CO_2 conversion factor of 20 for our analysis. The relative warming impact of N_2O is less affected by the time period of comparison because it is relatively long-lived. We use a conversion factor of 200, again based on a 100 year time frame for comparison.

In Table III-B, we have adjusted the estimates of the three studies by using our preferred GHG conversion factors in each. We also adjusted all estimates except Ho and Renner's "advanced" case to a base gasoline fuel efficiency of 30 mpg (Unnasch et al. used 27.5 and Ho and Renner used 29 mpg). We have kept the fuel efficiency of Ho and Renner's advanced case at 35 mpg[7]. We show the original estimates of the authors in Table III-A to show the effects of our adjustments. However, because we believe that some of the GHG conversion factors used to derive the estimates in Table III-A are too high, we will base our further discussion of the relative impacts of the alternatives on the adjusted values in Table III-B.

The adjusted estimates for the relative GHG impact of natural gas vehicles ranges from a net reduction of 22% in GHG emissions compared to the base case gasoline vehicle, to a 12% higher GHG impact of NGVs relative to gasoline. The factors which make the biggest difference in the estimates are the assumed tailpipe emissions of CH_4 and N_2O from NGVs, the amount of natural gas which is assumed to leak from the transport and distribution system, the relative thermal efficiencies of NGVs vs. gasoline vehicles, and the amount of energy required to compress natural gas. Unnasch et al. appear to have neglected the contribution of natural gas leakage, whereas DeLuchi assumes a 0.5% loss of natural gas by leakage. Ho and Renner assume a 1.5% leakage rate

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[7] In their "advanced case" Ho and Renner assume 35 mpg for gasoline engines, and adjust the efficiencies of alternative fuelled vehicles by their assumed thermal efficiency advantage, of 1.10 for CNG and 1.15 for methanol.

for their "current" technology case, and 0.5% for their advanced case. If we further adjust the emissions estimates of Unnasch et al. to include 0.5% leakage of natural gas, this increases the calculated NGV emissions by 13 g/mi of CO_2 equivalent, raising the overall NGV emissions to 327 to 365 g/mi, or a GHG reduction relative to gasoline of 9 to 18%. The more optimistic estimate assumes that only 0.65 g/mi of CH_4 is emitted at the tailpipe, and that the amount of energy needed to distribute the natural gas is only 2.6% of the total energy content of the gas. Both of these are at the low end of the expected range for these values. DaLuchi assumes tailpipe CH_4 emissions of 1.4 g/mi as a base case, and Ho and Renner assume 1.9 g/mi for "current" technology and 1.5 g/mi for "advanced". Thus 18% GHG reduction can be regarded as an optimistic ostimate which may be realized if tailpipe CH_4 emissions are low and if the energy required to deliver the natural gas is at the low end of the expected range. The 12% increased GHG impact of NGVs (Ho and Renner's estimate as adjusted by us) couples a high estimate of tailpipe CH_4 emissions, a high estimate of tailpipe N_2O emissions, the assumption that N_2O emissions will be 50% higher for NGVs vs. gasoline vehicles (0.3 g/mi vs. 0.2), a high estimate of natural gas leakage (1.5%), and the assumption that there will be no thermal efficiency advantage of NGVs vs. gasoline vehicles. Taken altogether, these yield what we regard to be a highly pessimistic estimate of the relative impact of NGVs vs. gasoline vehicles. Using more optimistic assumptions, Ho and Renner estimate a reduction in GHG impact of 9% for NGVs vs. gasoline vehicles.

It appears to us that a best estimate of the relative GHG impact of NGVs vs. gasoline vehicles would be a slight benefit from NGVs, on the order about 15% for a dedicated vehicle. It must be recognized however, that this is

critically dependent on vehicle technology, since the two factors which most affect the calculation are tailpipe CH_4 emissions and relative thermal efficiency of NGVs vs. gasoline vehicles. Optimistically, a benefit of as much as 20% may be possible in a dedicated vehicle. A dual-fuelled vehicle will likely lose the thermal efficiency advantage of operation on natural gas, resulting in a GHG impact roughly the same as gasoline. The studies we examined did not consider the possibility that the thermal efficiency of a dual-fuelled vehicle might be even worse than a gasoline vehicle, although there is some data indicating that this may be the case (EPA 1990). This could lead to a higher GHG impact from natural gas compared to gasoline.

Methanol fuel derived from natural gas is found to have roughly the same GHG impact as gasoline, if it is assumed that there is a thermal efficiency advantage of methanol vs. gasoline, as assumed by DeLuchi (15% advantage), Unnasch et al. (6% advantage) and in Ho and Renner's "advanced" case (15% advantage). Ho and Renner's "current" technology case, which assumes no efficiency advantage for methanol, finds a 16% increase (adjusted by us as explained above) in GHG impact relative to gasoline. Testing of prototype vehicles indicates an efficiency advantage of about 5% for FFVs and 15% for dedicated methanol vehicles (Unnasch et al. 1989, DeLuchi 1990b, Ho and Renner 1990).[8] In Table III-C we present the result of our further adjustments to the values calculated in the three studies for the GHG impact of a vehicle operated on methanol from natural gas. Based on this, we conclude that a

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[8] An analysis by EPA indicates that an efficiency advantage as high as 30% may be achievable in a dedicated methanol vehicle. However, at least half of this can only be achieved in a lean burn vehicle (high air to fuel ratio). Such a vehicle would have difficulty attaining the NO_x standard (DeLuchi, 1991, personal communication; Carl Moyer, 1991, Acurex Corporation, personal communication).

dedicated methanol vehicle will have about the same GHG impact as a gasoline vehicle, whereas a methanol FFV will have a slightly greater GHG impact (+5%).

Table III-C
Further Adjustment of Calculated GHG Impact of Methanol from Natural Gas
Percent Change Relative to Gasoline

Base Study	FFV (rel. effic. 1.06)[9]	Dedicated (rel. effic. 1.15)[1]
DeLuchi 1990b	+3%	-1%
Unnasch 1989	-8% to +2%	-14% to -5%
Ho and Renner 1990		
--current	+10%	+2%
--advanced	+4%	-3%

All three studies find a significant increase in GHG emissions for vehicles operated on coal-derived methanol, in the range of +70 to +120%.

It has been proposed that natural gas which is currently being vented or flared could instead be captured and converted to methanol fuel. Since the carbon in this wasted gas is already being released to the atmosphere as CO_2[10], if the gas is instead collected and converted to methanol, the only additional CO_2 impact is from the use of process fuels not derived from the use of process fuels not derived from the waste gas. DeLuchi (1990b) estimates that methanol from waste gas would have only about 10% of the GHG impact of gasoline. However, as discussed in Section III, the amount of vented and flared gas worldwide is limited.

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[9] Relative thermal efficiency relative to gasoline

[10] Assume that all of the gas is flared. If some fraction is vented, there will be a larger GHG benefit of collecting and using the gas. Although the fraction of gas vented is not known, it is thought to be a small part of the total vented or flared.

Another proposal for methanol supply is to have a system which gasifies coal for conversion to electricity during peak electricity demand periods, and to use the same system to manufacture methanol in the off-peak periods. DeLuchi (1990b) finds that the methanol derived in this scheme would still have a higher GHG impact than gasoline. Assuming a methanol vehicle with a 30% thermal efficiency advantage over gasoline (as discussed above, an efficiency advantage higher than 15% is unlikely to be achieved), DeLuchi calculates that methanol from this source would have a GHG impact of +30% relative to gasoline[11]. The amount of methanol which could be supplied in this way is also likely to be rather limited (DeLuchi 1990b).

Thus, the largescale use of the fossil-based alternative fuels discussed here offers only a small potential for GHG reduction. The most promising alternative appears to be natural gas, which optimistically could yield up to a 20% reduction in impact per vehicle mile in a dedicated vehicle, although we regard a 15% reduction or less as much more likely. Although CNG on average is expected to have a lower GHG impact than methanol, this is highly dependent on vehicle technology. A gasoline engine modified to run as a dual-fuelled CNG vehicle will have lower efficiency and possibly higher methane emissions than a vehicle optimized for operation on CNG. It is possible that a dual-fuelled CNG vehicle would have a higher GHG impact than a well designed methanol vehicle. However, a well designed, dedicated CNG vehicle should have a lower GHG impact than its methanol counterpart due to the inherent differences in the fuels. Future improvements in technologies

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[11] DeLuchi compares an integrated gasification combined cycle (IGCC) plant which generates electricity only to an IGCC which generates the same amount of electricity plus methanol. The additional CO_2 emissions which result he attributes to methanol production.

may lower the GHG impact of either CNG or methanol relative to gasoline.

We have discussed only at the GHG emission impact of displacing gasoline in light-duty vehicles with alternative fuels. Both DeLuchi (1990b) and Unnasch et al. (1989) find that displacing diesel fuel in heavy duty vehicles with any of the fossil-based alternatives discussed above results in higher GHG emissions. This is because a diesel engine is much more efficient than a gasoline engine. Diesel engines work best on high cetane, low octane fuels. Methanol, ethanol and natural gas are even higher octane than gasoline, making them poor substitutes for diesel fuel.

B. Biomass Fuels

Through the process of photosynthesis, growing plants incorporate carbon from atmospheric CO_2 into the plant. When this carbon is converted to a bio-fuel and then released through combustion, this simply restores the atmospheric CO_2 which was removed when the plant was grown. Thus, if biomass were converted to a fuel in a closed system, where the process energy for producing, harvesting and converting the biomass to a fuel were also provided by biomass without any combustion of fossil carbon, and where no net devegetation occurred, the use of this fuel would result in no net release of CO_2 to the atmosphere. Some analyses have therefore made the assumption that using bio-fuels in vehicles would result in a 100% reduction of GHG emissions compared to gasoline.

However, although biofuels may have the potential to be produced in a manner which virtually eliminates net CO_2 emissions, fuel ethanol produced in the U.S. today (which is primarily made from corn) falls far short of this potential. Fossil fuel inputs are required to produce fertilizer, to operate

farm machinery, to convert the feedstock into ethanol, and to transport the product to consumers.

Here we discuss the main sources of GHG emissions in the production of ethanol or methanol from two of the main feedstocks of interest, corn and lignocellulosic materials[12] (wood, herbaceous crops, and some waste materials). Table IV summarizes some recent estimates of the amount of process energy required for each of the major steps in the biomass to ethanol pathway. Table V-A summarizes estimates of these same authors of the relative GHG emissions impact of ethanol vs. gasoline, based on the process energy requirements and the types of fuels used to provide this energy. One study (DeLuchi 1990b) has also examined the GHG emissions from the wood to methanol process.

The three studies which compare the GHG impact of corn ethanol to gasoline differ with respect to the parts of the fuel cycle and the specific GHGs which were included. Marland and Turhollow (1990) consider only CO_2 emissions and do not include the energy required to transport and distribute fuel ethanol. Ho and Renner (1990) include transport and distribution energy and also include CH_4 and N_2O emissions from vehicles. DeLuchi (1990b) includes all of the components considered by Ho and Renner (1990) and also includes CO and NMHC emissions, which influence atmospheric CH_4 and O_3 concentrations. The impact of the additional factors considered by Ho and Renner (1990) and by DeLuchi (1990b) is not much different for ethanol vs. gasoline, therefore the GHG impact of corn ethanol vs. gasoline calculated in the three studies is primarily dependent on CO_2 emissions from production of

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[12] The process for converting lignocellulose to ethanol is 10 to 20 years away from commercialization, but could be a promising option for the future.

Table IV

Summary of Energy Requirements to Produce Ethanol from Selected Crops
BTUs energy input per gallon of ethanol end-product

	Corn				Lignocellulosic crops	
	DeLuchi 1990b	Marland 1990	Ho and Sommer 1990 "advanced"	Ho and Sommer 1990 "current"	Lynd 1990[13]	Turhollow 1991[14]
Agricultural inputs:						
-- machinery use	7,000	7,000	17,000	17,000	---	---
-- fertilizer	14,000	15,000	16,000	16,000	---	---
-- other	1,200	1,000	---	---	---	---
Ag. input subtotal	22,200	23,000	33,000	33,000	12,900 (11,000-13,000)	4,200-31,000
Feedstock Transport	2,700	---	3,400	3,400	1,700	---
Feedstock Conversion	55,000	48,500 (42,000-57,000)	57,000	60,200	4,200[15]	---
Byproduct Credit	?	9,375	10,000	10,000	7,000[16]	---
Fuel Transport/Distrib.	2,900	---	4,200	4,200	850	---

[13] Values were reported as BTU in/BTU out. We assume that those values were based on an HHV for ethanol of 84,000 BTU/gal, and use this to back calculate.

[14] Personal communication with Anthony Turhollow of Oak Ridge National Laboratory, February 1991.

[15] Assumes that lignin, a by-product of the fermentation process, will be used for process energy for distillation. The only energy inputs counted here are embodied energy in chemical inputs and amortized embodied energy of the facility.

[16] Authors assume that there will be enough lignin to generate excess heat, which could be used to generate electricity.

Table V-A
Summary of GHG Emissions Estimates for Bio-fuels from Various Crops
Reduction or Increase Relative to Gasoline

Ethanol	
DeLuchi 1990b, corn	-6% (-36% to +12%)
Marland and Turhollow 1990, corn	-20% (-30% to -8%)
Ho and Renner 1990, corn, "advanced" case	+15%
Ho and Renner 1990, corn, current technology	+34%
Lynd 1989, wood	-82%
Turhollow 1991, lignocellulosic crops	-75 to -95%
DeLuchi 1991, wood	-60 to -75%
Methanol	
DeLuchi 1990b, wood	-65%

Table V-B
Percent Contribution of Fuel Cycle Steps to Overall GHG Impact of Corn Ethanol

	DeLuchi 1990b	Marland and Turhollow 1990	Ho and Renner 1990 advanced	Ho and Renner 1990 current
Feedstock Production and Transport[17]	16%	40%	31%	30%
Feedstock Conversion[18]	76%	60%	59%	57%
Fuel Transport and Distribution	3%	---	3%	3%
Vehicle Emissions[19]	6%	---	7%	10%

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[17] DeLuchi (1990b) subtracts a fertilizer by-product credit from this step.

[18] All by-product credits other than DeLuchi (1990b) fertilizer byproduct credit subtracted from this step.

[19] Does not include vehicular CO_2, which is assumed to be recycled atmospheric CO_2.

corn and conversion to ethanol. DeLuchi has recently recalculated the GHG impact of corn ethanol to include N_2O released from nitrogen fertilizers, an effect which he finds to be significant (DeLuchi 1991, personal communication). Since the other two corn ethanol studies considered here do not include this effect, we first compare the three studies without considering N_2O from fertilizer. We then discuss the implications of the impact of N_2O from fertilizer.

In the three corn ethanol studies, the biggest source of GHG emissions comes from feedstock conversion, or the milling and distillation of corn to ethanol, accounting for 57% to 76% of the overall GHG emissions (Table V-B). The high energy requirement at this step is compounded by the fact that almost all of this energy is provided by coal, which has relatively high CO_2 emissions per unit of energy compared to other fossil fuels. In fact, the different conclusions reached in each of the three studies regarding the GHG impact of corn ethanol result primarily from the different assumptions about the energy requirement for feedstock conversion, and to a lesser extent from the assumptions about agricultural energy inputs.

Marland and Turhollow reviewed the literature on energy requirements for corn to ethanol plants and also interviewed several plant owners. They found literature values ranging from 30,000 to 67,500 BTU/gallon of process energy, with most values falling in the range of 40,000 to 60,000 BTU/gallon. The lower end of this range (40,000 BTU/gallon) represents a state-of-the art facility (Marland and Turhollow 1990 and references therein). Based on conversations with facility owners, Marland and Turhollow conclude that an efficiency of 40,000 BTU/gallon "is not being achieved in existing, operating plants but is within design limits for an energy efficient, current plant with

superior maintenance" (Marland and Turhollow 1990). For their calculations, they use a range of 40,000 to 57,000 BTU/gallon, with a base case of 48,500 BTU/gallon.

DeLuchi (1990b) also reviews the literature, and for his base case adopts an efficiency of 55,000 BTU/gallon, based primarily on a detailed study of two existing corn to ethanol facilities (Jones 1989, as reported in DeLuchi 1990b). Ho and Renner base their assumed plant efficiency on a study conducted by Information Resources, but, because they believe this study has incorrectly calculated co-generation efficiency, they adjust the value of 51,400 BTU/gallon reported in this study to 65,000 BTU/gallon for the wet-milling process and 76,000 to 82,000 BTU/gallon (Ho 1989b). They use 65,000 BTU/gallon for their base case, and assume efficiency can be improved 15%, to 57,000 BTU/gallon for their advanced case (Ho and Renner 1990).

The three studies also take somewhat different approaches to calculating agricultural energy to raise and harvest corn. The primary difference between the Ho and Renner (1990) vs. the Marland and Turhollow (1990) calculations is the assumed yield of corn of 90 vs. 119 bu/acre, respectively. DeLuchi (1990b) instead bases his calculations on energy consumption per bushel of corn, and derives agricultural energy estimates which are similar to those of Marland and Turhollow. Since the average corn harvest for 1984-1988 was 110 bu/acre (DeLuchi 1990b), and since corn yield has been steadily rising, the Ho and Renner yield assumption appears to us to be too low and thus the energy inputs too high to be regarded as a representative value for average quality farmland. However, the Ho and Renner estimate may be representative of the inputs which would be required to raise corn for a largescale fuel ethanol program, since it may be necessary to use marginal quality land where yields

would be lower than the average.

DeLuchi has recently revised his estimate of GHG emissions from corn ethanol to include N_2O released from nitrogen fertilizers applied to corn fields (DeLuchi 1991, personal communication). A recent review of N_2O emissions from fertilized soils (Eichner 1990) includes data from two studies (Cates and Keeney 1987, Duxbury and McConnaughey 1986) which compared N_2O release from cornfields after addition of nitrogen fertilizer to N_2O release from an unfertilized control plot. Table VI summarizes these two studies. Each of these studies compared two different types of nitrogen-fertilized test plots to "unfertilized" controls[20].

Table VI

Summary of Two Studies of N_2O Emissions from Corn Fields

Trial[21]	Form[22]	lb N/acre	Duration (days)	lb N_2O-N/acre contr.	expt.	diff.	duration/runoff correction[23]
C&K(A)	CN	107	85	0.27	0.27	0.00	0.00
C&K(B)	U	107	85	0.27	2.23	1.96	3.92
D&M(A)	M,AA	161	365	0.30	3.21	2.91	5.82
D&M(B)	M,AA,U	212	365	0.30	4.64	4.34	8.68
Average						2.30	4.61

The amount of N_2O released from the fertilized plots minus the amount

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[20] The control plot used by Duxbury and McConnaughey (1986) was not completely unfertilized; all plots received an initial input of 17.8 lb N/acre ammonium nitrate as a "starter fertilizer" two months prior to the beginning of the experiment. Cates and Keeney (1987) used a nearby unfertilized pasture containing grazed Kentucky bluegrass as their control.

[21] C&K = Cates and Keeney 1987; D&M = Duxbury and McConnaughey (1986). A or B are arbitrary labels to designate two different experiments in each study.

[22] CN = calcium nitrate, U = urea, M = manure, AN = ammonium nitrate.

[23] As in Eichner (1990). See text for explanation.

released from the control plot is the N_2O release attributable to nitrogen application. The four experiments in Table VI found N_2O release rates due to fertilization ranging from 0 to 4.34 lb N_2O-N/acre. These values only include N_2O generated during the sampling period, so for the Duxbury and McConnaughey (1986) emissions, this is less than annual emissions. The values also do not include N_2O generated from nitrogen fertilizer in runoff. Eichner (1990) corrects for both short duration and N_2O in runoff by multiplying measured values by a factor of two. Although she does not break out how much of this is to correct for runoff vs. short duration, the experiments she reviewed (including both the studies discussed here) generally monitored N_2O release from the time of nitrogen application until N_2O release approached background levels. Thus, the correction factor primarily corrects for non-inclusion of N_2O from runoff.

The average N_2O release for the four experiments, including the runoff correction, is 4.6 lb N_2O-N/acre. Using a yield of 300 gallons of ethanol per acre, this translates to an additional 2200 g CO_2 equivalent per gallon ethanol, or 94 g CO_2 equivalent per mile[24]. This increases the GHG impact of corn ethanol by about 25 percentage points, relative to gasoline.

DeLuchi finds that N_2O release from fertilizers does not make a big contribution to the GHG impact of ethanol or methanol from wood because the amount of nitrogen fertilizer used is much smaller (DeLuchi 1991, personal communication).

Trace gas emissions from soils tend to be difficult to measure and highly variable, changing with temperature, season, soil moisture, and a variety of other factors. Further studies should be undertaken to verify and better

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[24] Assumes 15% thermal efficiency advantage for ethanol vs. gasoline.

quantify the contribution of N_2O emissions from nitrogen fertilizers to the GHG impact of energy crops. However, in the mean time it is prudent to use the best data available, and to include N_2O emissions from nitrogen fertilizers in calculations of the GHG impact of fuels made from energy crops. We therefore add +25% to the three corn ethanol studies cited above, as a rough approximation of the fertilizer N_2O effect, changing DeLuchi's estimate of the GHG impact of corn ethanol to +30%, Marland and Turhollow's estimate to +5% (range -5% to +17%), and Ho and Renner's estimates to +60% for current technology and +40% for advanced technology.

Based on our examination of the input assumptions, we conclude that Marland and Turhollow's estimate of GHG emissions from corn ethanol compared to gasoline is likely to be optimistic, because it couples a relatively high-efficiency ethanol plant with the assumption that the quality of agricultural land used for a largescale fuel ethanol program would be similar to that of existing corn acreage. Ho and Renner's estimate is likely to be pessimistic, since it assumes a relatively low ethanol plant efficiency. Without the fertilizer N_2O effect, we conclude that a reasonable mid-range estimate for the GHG impact of corn ethanol would be rough equivalence with gasoline, with a range of about -20% to +20%. With inclusion of the N_2O effect we conclude that the GHG impact of corn ethanol is about 25% greater than gasoline, with a range of +5% to +45%.

Estimates of the CO_2 emissions from ethanol derived from lignocellulosic materials indicate a reduction of 60 to 95% compared to gasoline. The 95% reduction estimate is based on CO_2 emissions for crop production only (Turhollow 1991, personal communication), and is therefore likely to be optimistic. The main reason for the reduced GHG impact is that the lignin

fraction can be used as a process fuel for the distillation step, thus avoiding almost all net CO_2 emissions from this step. DeLuchi (1990b) estimates a reduction of 65% in GHG emissions for methanol from wood compared to gasoline. Here also, the main reason is that a fraction of the feedstock is also used as the process fuel. Corn stover could be used for the corn to ethanol process as well, with similar consequences for net CO_2 emissions. Elimination of net CO_2 emissions from the corn ethanol plant would lower the GHG impact of corn ethanol to about -35% relative to gasoline (including fertilizer N_2O). However, it is easier to use a biofuel for this step in producing either methanol or ethanol from lignocellulose since the process fuel is derived from the feedstock material, avoiding the necessity of harvesting a crop residue.

Several important points emerge from these studies. One is that by any method of calculation, the net GHG emissions from corn ethanol are substantial. Another is that efforts to reduce net GHG emissions from corn ethanol should focus on improvements in the feedstock conversion process, and on reduced inputs of nitrogen fertilizers. Improvements in the feedstock conversion process could include an increase in the overall process efficiency, the use of a less carbon-intensive process fuel such as natural gas, or the use of bio-fuels such as corn stover[25] to fuel the process. Finally, other feedstocks besides corn are likely to yield greater reductions, especially if it is easier to use a bio-fuel for process energy and if production of the crop does not require intensive use of nitrogen fertilizers.

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[25] Some corn stover would have to be left in the field for erosion control.

Thus, if biomass fuels are to be used for GHG emissions reductions, either alternative feedstocks should be used, or substantial changes made in the corn to ethanol conversion process, or both. The GHG impact of corn ethanol will be +25% higher than gasoline if coal is used as the process fuel, about 35% less than gasoline is corn stover is used for the process fuel. Improved biomass processes such as methanol or ethanol from lignocellulose will have a GHG impact of about 70% less than gasoline.

C. Electricity

Electric vehicles (EVs) do not directly emit any pollutants or greenhouse gases; emissions associated with their use will occur at the electric power plants and in the fuel cycles to produce power plant fuels. Table VII summarizes the overall GHG emissions (as grams CO_2 equivalent) produced per kilowatthour (kWH) of electricity delivered to the outlet when the

Table VII
GHG Emissions from Electricity Generation[26]

Source of Electricity:	grams CO_2 equivalents/KWH
Coal	1081
Oil	937
Gas	661
Nuclear	59
Solar	0
U.S. electric fuel mix, year 2000[27]	743
EV overnight recharging fuel mix[28]	952

Source: Adapted from DeLuchi (1990b)

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[26] Includes emissions from recovery, transport and processing of fuel

[27] As reported in DeLuchi (1990b): coal 52%, oil 8%, gas 16%.

[28] From Kiselewich et al. (1982), as reported in Hamilton (1989). This study examined the likely fuel mix for electric power used to recharge electric vehicle batteries overnight. Results: coal 73.9%, oil and gas 14%. We assume that the oil and gas total will be 1/3 oil and 2/3 gas.

electricity is generated by various fuels (adapted from DeLuchi 1990b)[29]. We have also calculated the GHG emissions generated by two fuel mixes, the average electricity fuel mix projected for 2000 (as reported in DeLuchi 1990b) and the fuel mix which one study calculates would be used for overnight recharging of EVs (Kiselewich 1982 as reported in Hamilton 1989).

Two recent studies have reviewed the status of current and projected EV technology (DeLuchi et al. 1989, Hamilton 1989). DeLuchi et al. report an efficiency of 2.35 mi/kWH for an electric car with an advanced sodium sulfur battery under development by BMW, and efficiencies for some projected vehicle technologies as high as 3.38 mi/kWH. For several earlier prototype electric cars with lead/acid batteries, reported efficiencies at the battery outlet were 2.99 to 3.41 mi/kWH, which with typical battery efficiencies of 70% and recharger efficiencies of 90% would translate to efficiencies at the outlet of 1.88 to 2.15 mi/kWH. DeLuchi et al. (1989) project efficiencies of electric vans to be 1.64 to 2.22 mi/kWH.

Hamilton (1989) reports projected efficiencies for electric cars of 1.99 to 2.64 mi/kWH, and for electric vans 1.38 to 1.88 mi/kWH (Table 1.6 in Hamilton 1989). In projections of the effect of EVs on electricity demand, Hamilton takes the low end of the range of efficiencies for cars and vans and reduces them by an additional 20% to account for decreased efficiency due to recharging after only partial discharge of the battery. This reduces projected efficiencies of in-use EVs to only 1.67 mi/kWH for cars and 1.11 mi/kWH for vans (Table 3.2 in Hamilton 1989). If the 20% shallow discharge penalty were instead applied to the middle of the range of efficiencies, this would result in projected in-use efficiencies of 1.9 mi/kWH for cars and 1.3

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[29] Includes GHG emissions from fuel cycles of power plant fuels.

mi/kWH for EVs. Whether or not the shallow discharge penalty is actually incurred will depend on the battery technology and on how the vehicle is operated.

The projected efficiency of EVs is the biggest source of uncertainty about the GHG emissions which would result from their use. Table VIII summarizes the GHG emissions which would occur from three different efficiency levels for EVs, and with various sources of electricity. The highest efficiency (3.38 mi/kWH) is the high end of the range projected by DeLuchi et al. (1989), the intermediate efficiency (2.6 mi/kWH) is consistent with estimates by DeLuchi (DeLuchi 1990b)[30] and the lower (1.9 mi/kWH) is consistent with estimates by Hamilton (1989).

Table VIII
GHG Emissions from Electric Vehicles

Source of Electricity:	GHG Emissions, g/mi CO_2 equivalent 1.9 mi/kWH	2.6 mi/kWH	3.4 mi/kWH
coal	569 (+44%)	414 (+5%)	328(-17%)
overnight recharge fuel mix[31]	501 (+27%)	365 (-7%)	289(-27%)
year 2000 electric fuel mix	391 (0%)	285[32] (-28%)	226(-43%)
natural gas	348 (-12%)	253 (-36%)	200(-49%)
solar	0 (-100%)	0 (-100%)	0(-100%)

These values can be compared to the base case emissions for gasoline vehicles of 394 g CO_2 equivalent/mi derived by DeLuchi (1990b). If the highest efficiency is realized, all fuel mixes result in a net reduction of

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[30] We back calculated this assumed efficiency in DeLuchi (1990b) by dividing the 743 g/kWH which results from the year 2000 assumed power mix by the 285 g/mi reported for EV emissions, to get 2.61 mi/kWH.

[31] As projected in Kiselewich et al. (1982).

[32] This is the base case in DeLuchi (1990).

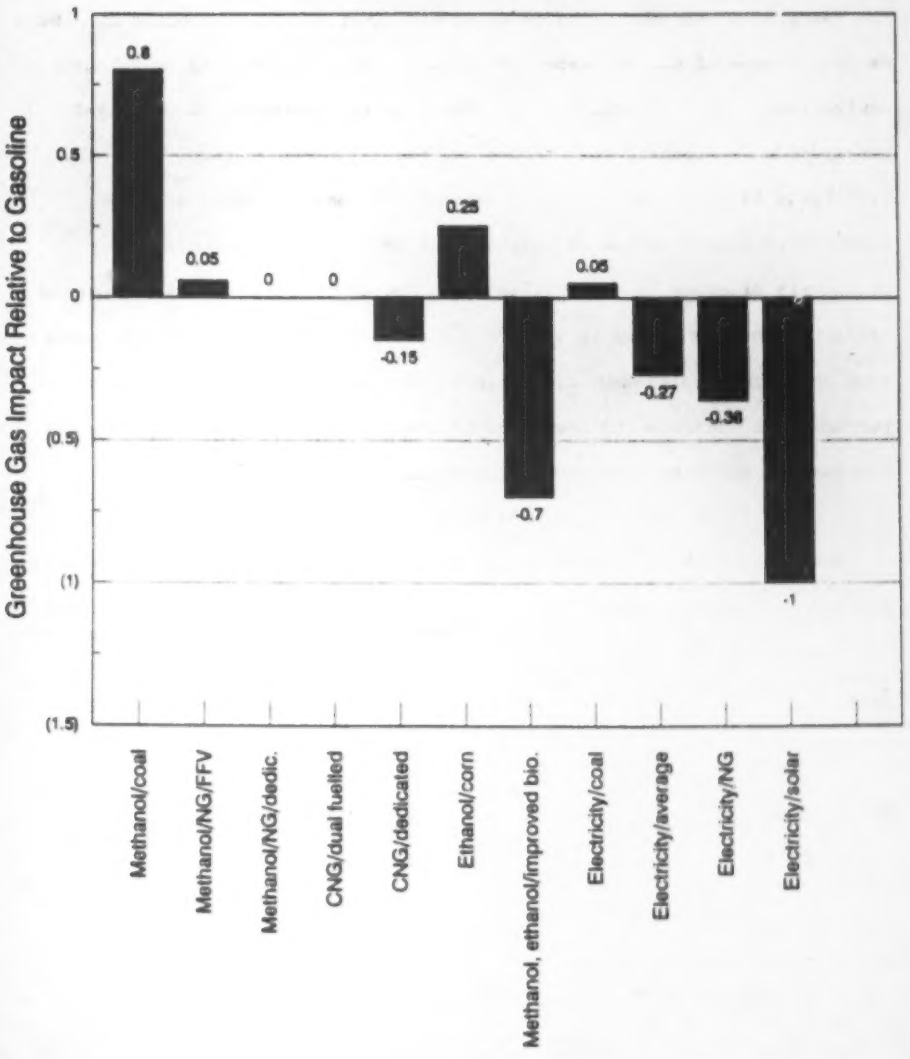
GHG emissions vs. gasoline, ranging from -17 to -100%. If the more pessimistic assumptions about efficiency is realized, several fuel mixes will result in a net increase in GHG emissions. In the absence of policies to discourage the use of coal-fired power for overnight battery recharging, the actual fuel mix used is, in our opinion, most likely to resemble that predicted in a study for EPRI (Kiselewich et al. 1982). In this case, the highest efficiency EV would produce 27% less GHGs, the intermediate efficiency EV would produce 7% less GHGs than gasoline, and the low efficiency EV would increase GHG emissions by 27%. If the EV electricity demand is met with solar energy or other very low CO_2 sources, GHG emissions could be virtually eliminated.

D. Summary of GHG Impacts of Alternative Fuels

Figure 1 summarizes our best estimates of the GHG impact of each of the alternatives relative to gasoline, based on the above analysis. The options which yield the greatest reductions per vehicle are improved biofuels, which decrease GHG emissions by 70% relative to gasoline (including methanol or ethanol from cellulosic materials, and any other biomass fuel which uses a biofuel for the feedstock conversion process and which avoids heavy use of nitrogen fertilizers) or electricity from low GHG emitting sources, which could result in up to 100% reduction of GHG emissions. A modest reduction in GHG emissions (-15%) results from the use of CNG in dedicated vehicles. Most other options are roughly equal to, or slightly worse than the gasoline base case. Methanol from coal is substantially worse than gasoline (+80%).

Figure 1

Greenhouse Gas Impact of Alternative Fuels
(light duty vehicles)



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III. Feedstock Requirements

The total GHG emissions reduction (or increase) which will result from substituting alternative fuels for gasoline will depend on two factors: the change in GHG emissions per vehicle, and the total number of vehicles which are operated on the fuel. We examined the first factor in Section II. Here we review some of the estimates of feedstock availability for fossil-based derivatives, and for biomass. We also discuss estimates of potential penetration of electric vehicles, given their limited range.

Table IX lists the amount of ethanol, methanol, natural gas, and electricity needed at the refueling station (or electric outlet) to completely displace the 120 billion gallons, or 15 quads of motor gasoline projected to be consumed in the U.S. in 2010 (EIA 1990). We do not suggest that complete displacement is possible; we simply present these numbers as a benchmark to indicate the magnitude of the problem of displacing a significant fraction of gasoline with any of these fuels.

Table IX

Fuel Requirements at the Refueling Station to Displace Motor Gasoline

Fuel	BTU/volume HHV	Relative Efficiency[33]	Quads	Amount Needed 100% displacement
Gasoline	124,600 BTU/gall.	1.00	15.0	120 billion gallons
Ethanol	84,600 BTU/gall.	1.14	13.2	156 billion gallons
Methanol	64,500 BTU/gall.	1.15	13.0	202 billion gallons
Natural Gas	1,073 BTU/ft^3	1.06	14.2	13.2 TCF
Electricity	---	--	3.6 to 6.4	1050 to 1900 terawatthours

[33] As projected in DeLuchi (1990b).

The values in Table IX, except those for electricity, are based on the energy content of each fuel, adjusted for differences in projected thermal efficiencies of the vehicles. As discussed above, the potential thermal efficiency advantage for methanol, ethanol, or CNG will only be realized if vehicles are designed to take advantage of it, which is more likely to occur in dedicated vehicles than in dual- or flexible-fuelled vehicles.

We estimated the amount of electricity required to displace all motor gasoline in 2010 as follows. Vehicle miles travelled (VMT) by passenger cars in 1988 was 1.429 trillion, VMT of light trucks[34] was 0.491 trillion (DOT 1988). These two vehicle categories account for nearly all motor gasoline consumption. The U.S. Department of Energy projects that total VMT will increase by 49% by 2010 (EIA 1990). We assume that VMT for each vehicle category increases by this amount, to 2.129 trillion for passenger cars and 0.731 trillion for light trucks. Our "low efficiency" estimate assumes that passenger car EV efficiency will be 1.9 mi/kWH, and light truck EV efficiency 1.0 mi/kWH. In this case, 1900 TWH would be required to run the entire fleet on electricity. Our "high efficiency" case assumes a passenger car EV efficiency of 3.4 mi/kWH, and light truck efficiency of 1.7 mi/kWH, requiring 1050 TWH to fuel the fleet.

A. Natural Gas Derived Alternatives

Natural gas can either be used directly in vehicles, or converted to methanol. Direct use of natural gas results in greater air quality benefits, lower overall GHG emissions, and requires significantly less natural gas as a feedstock. On the other hand, conversion of natural gas to methanol will make

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[34] The category "single unit trucks" in DOT (1988).

it easier to utilize gas from locations other than North America, since it is easier to ship methanol across oceans than to ship liquefied natural gas.

Displacing all motor gasoline with CNG would require 13.2 TCF of natural gas per year at the refueling station. Displacing motor gasoline with methanol made from natural gas would require about 17.4 to 18.7 TCF/yr, assuming a thermal conversion efficiency of 65 to 70% for converting natural gas to methanol. In 1988 U.S. gross production of natural gas was 19.8 quads or 18.5 TCF (AGA 1990). Thus displacing all motor gasoline with CNG would require approximately a 70% increase in domestic production of natural gas, and displacing it with methanol from domestic natural gas would require approximately a doubling of U.S. gas production.

The American Gas Association estimates that by 2010 natural gas production could be increased to 21 to 26 quads, or up to an additional 6 quads/yr over present levels (German 1990). This would be enough to displace about 40% of motor gasoline if used for NGVs, or about 30% if used for methanol, if all of this expanded production were used for vehicle fuel. More realistically, 1 to 2 quads may be available for vehicle use (DOE 1989; M. German 1991; AGA, personal communication), allowing displacement of 7 to 13% of motor gasoline with CNG, or 5 to 9% displacement with domestic methanol.

If expansion of the natural gas supply and displacement of fuels which emit more GHGs is to be pursued as a GHG emission reduction strategy, there are other possible uses for this additional natural gas which might yield much greater GHG reduction benefits. Using natural gas to displace coal will yield a greater overall GHG reduction benefit than using it to displace oil, because coal produces more GHGs per unit energy than oil. Using natural gas to displace oil in the electric utility or industrial sector will also yield a

greater GHG benefit than using it to displace oil in the transportation sector. Methane emissions in the natural gas to vehicle fuel cycle, as tailpipe emissions or losses via leakage in low pressure distribution lines, make a significant contribution to the overall GHG impact. Using natural gas to displace oil in power plants avoids both these sources of methane emissions, since the gas would be delivered to plants via high pressure lines where leakage is expected to be minimal and since, unlike tailpipe methane emissions, power plant methane emissions are trivial and do not contribute significantly to the overall GHG impact of a power plant (Gleick 1989).

Table X shows estimates of the total natural gas resource base available in the U.S., as estimated by the U.S. Department of Energy (EPA 1989). Proven reserves of about 200 quads would last only about 12 years at current consumption levels. If one includes all categories, the resource may be as large as 1200 Quads, which DOE estimates would last 70 years. Note, however, that 60% of this total is from either undiscovered or unconventional sources.

Table X

Estimated U.S. Natural Gas Resources
(in Quads)

Resource type	Lower 48	Alaska	Total
Proven reserve	162	34	196
Probable	110	3	113
Extended reserve growth in non-associated fields	121		121
Gas resources associated with oil reserve growth	63		63
Undiscovered	360	95	455
Unconventional			264
Total			1212

Source: EPA (1989)

Furthermore, DOE estimates that only about 2/3 of the total would be recoverable at less than $5/mmBTU (as cited in EPA 1989). This quantity would last about 45 years at current consumption rates of consumption.

It has been suggested that natural gas which is currently flared could instead be converted to methanol and used as a vehicle fuel. The amount of natural gas which is flared in the U.S. is only 0.14 TCF, which if converted to methanol could displace less than 1% of gasoline consumption. Worldwide, about 3 TCF of natural gas are vented or flared (EIA 1989). Not all of this will be collectable and certainly not all of it will be available for sale to the U.S.

The U.S. currently consumes 27% of the world's natural gas production. If we assume that the proportion of vented and flared gas available to the U.S. would be proportional to its share of total gas consumption this would mean that 0.9 quad would be available for conversion to methanol, which would yield about 0.6 quad of methanol, which could displace about 5% of U.S. gasoline consumption.

There are additional issues which bear on the overall GHG reduction benefit of converting vented and flared natural gas to methanol. The amount of vented and flared natural gas has been declining and is expected to continue to do so. To project the benefit of a fuel methanol program which uses this source, it is necessary to project how much the practice of venting and flaring would decline in the absence of such a program. Even without a fuel methanol program, this practice is likely to diminish significantly. As with other sources of natural gas, there may also be alternative uses for the collected natural gas that otherwise would have been vented or flared that would yield greater GHG reduction benefits than using it for vehicle fuel.

B. Coal Based Alternatives

Making enough methanol from coal to displace all motor gasoline would require about 17 to 21 quads of coal per year, assuming a coal to methanol thermal conversion efficiency of 55 to 69%. This would represent approximately a doubling of U.S. annual coal production. Thus, similar to powering vehicles from a natural gas feedstock, powering them from coal as a feedstock would require a percentage increase in coal production approximately equal to the percentage gasoline displaced. However, U.S. coal reserves are estimated to be much larger than natural gas reserves. The U.S. is estimated to have 290 billion tons of recoverable coal reserves, or about 6400 Quads. At current rates of consumption this supply would last well over 300 years.

C. Biomass

Biomass for fuel production would come from energy crops and from collection and utilization of waste materials. Since biomass wastes are composed largely of cellulosic materials, utilization of wastes for ethanol depends on further advancements in the lignocellulose to ethanol process. Wastes could also be used to generate biogas (a mixture of methane and CO_2) or methanol. In the first subsection below we discuss energy crops and in the second we discuss estimates of waste availability for energy production.

1. Energy Crops

The total amount of energy which is potentially available from energy crops depends on two factors: the amount of the crop which can be produced per acre, and the total acreage available. We discuss each of these factors below.

a. Availability of Land.

The amount of land used for crop production in the U.S. decreased from 564 million acres in 1982 to 328 million acres in 1988. Of the 235 million acre decrease, 54 million acres were idled through acreage reduction programs for major crops and 24 million acres of erosion prone land were removed from production through the Conservation Reserve Program. The other 158 million acres were shifted to other land uses (Wright et al. 1989).

Although some have suggested that the entire 236 million acres of former cropland could be devoted to energy crop production, this appears overly optimistic to us. Some of this land has likely been shifted to uses which cannot readily be shifted back into cropland. A more reasonable, and, in our view, still optimistic goal would be convert the 78 million acres of idled cropland to energy crop production. We will use this as the basis for several calculations below, but will also look at potential energy production should more or less land be available.

b. Yields

Table XI lists the yields of various energy crops per acre, and the yield of ethanol or methanol per acre. A corn yield of 3.34 tons/acre, or 119 bushels/acre was obtained in 1987, as reported in Marland and Turhollow (1990). There has been an upward trend in corn yields for the past several decades which is likely to continue. If yields increase by 1.5%/year, by 2010 an acre may yield 160 bushels or 4.5 tons, giving an ethanol yield of 400 gallons/acre. If marginal lands are used, yields will be significantly lower.

It is more difficult to determine what a reasonable average expected yield should be for trees and other lignocellulosic crops. Many decades of

Table XI

Reported Ethanol or Methanol Yields from Various Crops

Crop	Yield tons/acre	Yield gallons/acre
Corn	3.34	300 to 400 Ethanol
Sugar Cane		600[35] Ethanol
"	25[36]	451 "
"	6.36 (sugar)[37]	968 "
Sweet sorghum		
"		380 "
Trees	4 to 10 (dry)	400 to 1000 Ethanol[38]
		520 to 1540 Methanol[39]

research and selective breeding have gone into optimizing corn yields. The same is not yet true of yields of trees from silviculture. Commercial forestry yields for the late 1970s averaged 1 to 2 dry tons/acre (Sperling 1988). A recent study of the potential U.S. biomass resource estimated that yields of 3.6 to 6.9 tons/acre could currently be achieved and predicted that by 2010 yields of 5 to 10 tons/acre might be achieved on excellent sites (Tyson 1990, Appendix A). Lower yields would therefore be expected on average or below average sites. Lynn Wright of Oak Ridge National Laboratory suggests that an assumed yield of 5 dry tons/acre would be optimistic for average sites

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[35] From Sperling (1988)

[36] World average yield 1976-1982, from Buringh (1987).

[37] Optimum yield from test plot, as reported in Buringh (1987).

[38] Based on ethanol yield of 100 gallons/dry ton

[39] Based on methanol yield of 130 to 154 gallons/ dry ton.

today (Wright et al. 1989). We use a range of 4 to 10 tons/acre in Tables XI and XII. We regard the upper end of this range as highly optimistic and not likely to be achieved for large tree-planting programs in the near future, although eventually such yields may be obtained.

One dry ton of wood is expected to yield about 100 gallons of ethanol (Lynd et al. 1990) or about 130 to 150 gallons of methanol (Chem Systems 1989). The energy content of 130 gallons of methanol is equal to that of 100 gallons of ethanol.

c. Overall Potential of Energy Crops

In Table XII we present several calculations to estimate potential ethanol or methanol yield from energy crops. First we show the yield on the 78 million acres of crop land idled between 1982 and 1988[40]. Table XII also shows the amount of land needed to displace 10%, 50%, and 100% of projected 2010 motor gasoline consumption with ethanol or methanol (requiring 15.6, 77.5, and 156 billion gallons of ethanol, respectively, or 20.2, 101, and 202 billion gallons of methanol, respectively).

From Table XII, we conclude that displacing 10% of motor gasoline with ethanol or methanol from energy crops should be possible, since this will require between 13 and 40 million acres of trees or 39 to 50 million acres of corn, requiring about one fourth to two thirds the amount idled through various crop reduction programs. Displacing 50% of motor gasoline with ethanol from crops would be a much larger challenge, requiring 67 to 200 million acres of trees or 200 to 250 million acres of corn. Displacing 100% of motor gasoline with ethanol would require 135 to 517 million acres of land,

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[40] This assumes that the land is average quality and thus produces average yields. This may be optimistic, since much of the land taken out of crop production is of marginal quality.

Table XII

Land Requirements to Displace Motor Gasoline with Ethanol or Methanol from Energy Crops

Crop	Yield gallons/acre	Yield on 70 Million Acres billion gallons of ethanol	Millions of Acres Needed to Displace Motor Gasoline 10% Displacement	50%	100%
Corn	300 to 400 Ethanol	21 to 31 (15 to 20%)	39 to 51	194 to 250	388 to 517
Trees	400 to 1000 Ethanol	31 to 78 (20 to 50%)	18 to 39	78 to 194	156 to 388
	520 to 1500 Methanol	41 to 117 (20 to 58%)	13 to 39	67 to 194	135 to 388
Sugar cane	450 to 900 Ethanol	35 to 70 (22 to 47%)	17 to 34	86 to 172	172 to 344
Sweet sorghum	580 Ethanol	30 (20%)	41	204	408

an increase of from 40% to 165% of land in crop production (assuming no land currently in crop production is diverted to energy crops).

2. Availability of Waste Materials

Given the large amount of land needed for largescale substitution of motor gasoline with biomass fuels, it is desirable to find feedstocks which could supplement energy crops. Most waste materials are composed in large part of cellulosic materials, thus utilization of these materials as an ethanol feedstock will be made more feasible by further development and commercialization of the lignocellulose to ethanol conversion process. The same materials could be used to generate methanol.

Table XIII summarizes two estimates of the availability in the U.S. of various waste materials, including forestry residues, agricultural wastes and municipal solid waste. The study by Lynd et al. (1989) is based on a review of eight earlier studies, which used data collected between 1976 and 1982. The study by Tyson et al. (1990a) is based on recent data. We present these two estimates to demonstrate the broad range of estimates of potential alcohol production from wastes. Both studies also estimate the amount of ethanol which could be generated from the waste material. The lower quantity of ethanol could displace about 5% of motor gasoline, whereas the larger quantity could displace almost 40%. Methanol yield from cellulosic materials is roughly equal to ethanol on an energy equivalent basis, therefore the potential gasoline displacement is about the same.

Part of the reason for the very broad range results from the way in which the studies account for potential competing uses such as fertilizer, animal feed, erosion control, etc. Another very important factor is geographic concentration of the materials, and seasonality of availability. It is

Table XIII

Estimates of Availability of Waste Materials for Energy Production

Type of waste material:	Tyson (1990b)	Lynd (1989)
Logging residues		
--overall	76.2 dry tons	
--available	15-23[41]	
		55-348
Wood and paper mill		182 (91-253)
--overall	90.6	
--available	3	
Crop residues		
--overall	527	323-736
--available	19	177 (75-364)
Manure		
--overall		182-255
-- available		136 (10-227)
Municipal Solid Waste		
--overall		70-1512
--available	40[42]	91 (48-182)
Other		91 (502-864)
Total Ethanol Potential	8 billion gall.	60 billion gall.[43]

[41] Tyson estimated the overall resources only. In a personal communication with this author, Tyson suggested that 20% to 30% availability of the overall resource for energy would be a reasonable estimate. A more exact estimate is hampered by lack of data on forestry resources.

[42] Estimate of paper wastes, most of which would be diverted from the MSW stream.

[43] Lynd estimate based on degradable carbohydrate content of wastes. Resulting ethanol yields range from 36 to 103 gallons per dry ton.

difficult to estimate the effect of these factors because many of them (especially geographic concentration) are very site specific. Based on our review of several of the studies included in Lynd (1989), and based on discussions with the author of the Tyson (1990a) study, it appears to us that the latter study considers more of the likely constraints which may limit the availability of wastes for energy production. These include amount of residue needed for nutrients and erosion control, minimum quantities collectable by machinery, efficiency of machinery, need for a high enough geographic concentration of residues to fuel a conversion facility, inhibition of collection by adverse weather, and use for livestock grazing (Tyson 1991, personal communication). The Tyson study may be conservative due to over-constraint (Tyson 1991, personal communication). On the other hand, earlier studies cited by Lynd are likely to be optimistic because they consider some, but not all, of these constraints. In either case the amount of ethanol or methanol available from wastes could make a significant contribution, but further characterization of this resource, and especially more site specific analysis, is desirable.

D. Electricity

Displacing all motor gasoline with electricity would require from 1050 to 1900 TWH/year with overall EV efficiencies at the outlet of 3.4 or 1.9 mi/kWH, respectively. We present this calculation as a limiting case, since improvements in the performance characteristics of EVs, especially range (miles travelled between recharging) would have to occur before EVs could displace all motor gasoline. Total electricity production in the U.S. in 1987 amounted to 3,341 TWH. Thus the additional electricity required to power an

all electric fleet is equal to 31% to 57% of present U.S. electricity production.

A recent study (Hamilton 1989) estimates that EVs with a range of 85 miles could displace as much as 17% of all vehicle miles travelled (VMT). If we assume that this level of penetration would displace 17% of motor gasoline consumption this would require 180 to 320 TWH/yr, or 5.4 to 9.6% of current U.S. electricity production. A study performed for EPRI found that if EVs recharged overnight for a 6 am finish, this creates a peak which fits nicely in the late night valley for electricity demand, as shown in Figure 2. The graph labelled "with 6 am finish" shows the nighttime demand created by an EV fleet which requires 880 GWH/day. It appears that an even higher daily EV demand could be accommodated in the demand valley. If travel of the EV fleet is spread evenly over all the days of the year, a fleet which displaced 17% of VMT would require 490 to 877 GWH/day, which could be accommodated with increased use of present electric capacity at night. Since EV fleet travel won't be spread evenly over all the days of the year, and since some day-time recharging will certainly occur, this level of EV penetration is likely to require some additional capacity.

IV. Potential Reductions From Selected Substitution Scenarios

The change in GHG emissions which results from the substitution of each alternative fuel for gasoline is a function of the total amount of gasoline which can be displaced with the fuel and relative GHG impact of the alternative vs. gasoline. In Table XIV we summarize the change in GHG emissions which would result for several scenarios for displacing some or all motor gasoline.

FIG. 2 EHV IMPACT ON POWER DEMAND

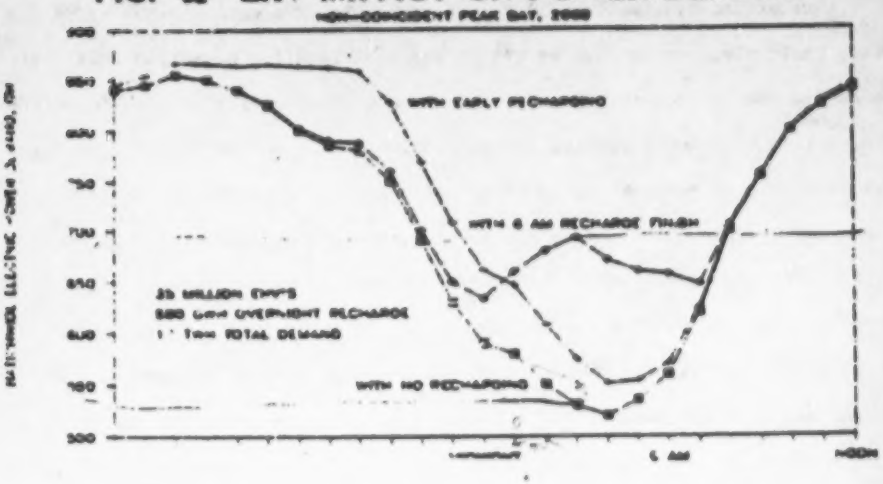

Table XIV

Selected Scenarios of Alternative Fuel Substitution and Resultant Change in GHG Emissions

Scenario:	Quads gasoline displaced (%)	GHG change per vehicle	total GHG change
CNG substitution			
--use all projected 2010 increased gas production	6 (40%)	-15%	-6%
--20% of gasoline vehicles	3.0 (20%)	-15%	-3%
--10% of gasoline vehicles	1.5 (10%)	-15%	-2%
Methanol substitution			
--vented and flared NG	0.6 (4%)	-90%	-3%
--increase NG production	4.2 (28%)	0 to +5%	0 to +1%
Ethanol or Methanol Production on 78 million acres of land			
-- from corn, N_2O included	2.2 (15%)	+25%	+4%
-- from corn, N_2O negligible	2.2 (15%)	0%	0%
-- lignocellulosic, 5 tons/acre	3.3 (22%)	-70%	-15%
-- lignocellulosic, 10 tons/acre	6.6 (44%)	-70%	-30%
Gasohol (10%) used in all gasoline vehicles			
-- corn ethanol, N_2O included[a]	1.5 (10%)	+25%	+3%
-- corn ethanol, N_2O negligible	1.5 (10%)	0%	0%
-- lignocellulose ethanol	1.5 (10%)	-70%	-7%
Electric vehicles, displace gasoline whenever limited range of EVs permits[44,45]			
-- overnight charging power mix	2.3 (17%)	-8%	-1%
-- average year 2000 power mix	2.3 (17%)	-28%	-5%
-- natural gas	2.3 (17%)	-36%	-6%
-- recharge with solar energy	2.3 (17%)	-100%	-17%

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[44] Hamilton (1989) finds that 17% of all vehicle miles travelled by gasoline vehicles could be displaced by electric vehicles with a range of 85 miles.

[45] Vehicle efficiency of 2.6 mi/KWH

The options which have the greatest potential to reduce GHG emissions from displacing motor gasoline are electricity or improved biomass fuels. Smaller reductions would be obtained from large-scale HGV penetration, or from a major effort to gather vented and flared natural gas and convert it to methanol.

Although electricity or biomass-based fuels have the potential to achieve significant GHG reductions, changes from the current technology need to occur before the full potential can be realized. In the case of ethanol, changes in the process for converting feedstocks into ethanol are needed to reduce or eliminate GHGs at this point. In the case of EVs, changes in the power mix for electricity generation are needed to achieve the maximum potential improvement.

V. Conclusions

Of the alternative fuels we've reviewed, only biofuels and electricity offer the potential for substantial reductions (>50% per vehicle) in GHG emissions from displacement of motor gasoline. In both cases, the GHG reduction benefit is highly dependent on the manner in which the fuel is produced. More modest reductions in GHG emissions (15 to 20% per vehicle) may be obtained from some fossil-based alternatives with optimized vehicles. Feedstock availability and other constraints will prevent displacement of more than 10 to 20% of motor gasoline with any one fuel in the near term.

The two factors which determine the GHG impact of electric vehicles are vehicle efficiency and the fuel mix used to generate the electricity. At the lower end of efficiencies projected for EV passenger cars (1.9 mi/kWH) and with electricity generated from coal, an EV would have a GHG impact 44%

greater than a 30 mpg gasoline car, whereas an EV whose efficiency was 3.4 mi/kWH would emit 27% less GHGs even on coal-fired electricity. Using a mid-range estimate for EV efficiency (2.6 mi/kWH), all fuel mixes except 100% coal would result in a GHG emission benefit, with coal giving only a 5% increase. At this EV efficiency, electricity from natural gas gives a 36% reduction in GHGs with current power plant technology. A reduction of up to 100% in GHGs is possible with the use of renewable sources of electricity such as solar energy. Thus, at mid-range efficiency, a significant penetration of EVs into the vehicle fleet will at worst result in about the same GHG impact as gasoline, and more likely will result in a significant reduction, especially if policies are adopted to encourage the use of lower GHG-emitting sources of electricity.

Penetration of electric vehicles is not constrained by feedstock considerations, since electricity can be generated from a diverse array of sources. In the near term, performance characteristics, especially the limited range of EVs, will be the most significant factor limiting market penetration. One study indicates that EVs with a range of 85 miles could displace up to 17% of VMT (Hamilton 1989). In the long term, advances in EV technologies will increase EV range, making possible further penetration of EVs into the vehicle fleet.

The bio-fuel which is currently most widely used is fuel ethanol from corn. The corn to ethanol process is very energy-intensive, requiring large amounts of coal (for distillation), natural gas (for fertilizer manufacture), and oil (to run farm equipment). Estimates differ on whether the net GHG release is greater than or less than gasoline. These differences reflect not only the different assumptions of various authors, they also reflect real

variability in the process of raising corn and converting it to ethanol. The biggest source of net CO_2 emissions is the corn to ethanol conversion facility. The second biggest source is CO_2 emissions from farming practice. A recent estimate indicates that N_2O released in the corn field from nitrogen fertilizers also contributes significantly to the overall GHG impact of corn ethanol. The overall GHG impact of corn ethanol is about +25% greater than gasoline, including the N_2O effect.

There are many improvements which could be made to the corn to ethanol process. Using natural gas rather than coal would reduce CO_2 emissions. Using a bio-fuel such as corn stover (the material left in the field when corn is harvested) would have an even greater impact, reducing the GHG impact of corn ethanol to approximately 35% less than gasoline (including the fertilizer N_2O contribution).

Processes to convert cellulosic materials to either ethanol or methanol result in an overall reduction in GHG impact of about 70% compared to gasoline, primarily due to the use of a biofuel to run the process, and to the fact that little or no nitrogen fertilizer is required to grow the feedstock. Such benefits are not limited to alcohols; any biofuel which is produced using biofuels for the process energy will result in a significant GHG benefit.

Reliance on energy crops alone for feedstock will limit the overall penetration of biofuels to about 10 to 20% displacement of gasoline due to limited availability of land. Processes which derive a fuel from cellulose can make use of waste materials, since most wastes (e.g. crop and forestry residues) are composed largely of cellulosic materials. Although penetration can certainly be increased by use of waste materials, the total amount of fuel obtainable from this source is highly uncertain. Estimates of waste

availability vary widely and often do not include important considerations such as geographic concentration and seasonality of the supply.

Of the fossil-based alternatives considered here, only methanol from coal is clearly detrimental, with a GHG impact of +80% with current technologies, or +30% in an optimal scenario involving coproduction of methanol and electricity using advanced integrated gasification combined cycle technology. Methanol from natural gas is calculated to have roughly the same GHG impact as gasoline, with slightly higher GHG emissions from a FFV vs. a dedicated methanol vehicle. CNG in a dedicated vehicle is expected to give a modest reduction (-15%) in GHG emissions relative to gasoline.

Although CNG is expected to produce somewhat lower GHG emissions than methanol on average, this is highly dependent on vehicle technology. A well designed methanol vehicle could have a lower GHG impact than a dual-fuelled CNG vehicle, but a well designed, dedicated CNG vehicle will likely have a lower impact than its methanol counterpart because of the inherent differences in the fuels.

Improvements in methanol and CNG vehicle technologies, and in the natural gas to methanol conversion process, are likely to be achieved in the future. This may lower the overall impact of these fuels relative to gasoline. GHG reductions of 20% or more vs. gasoline may be achievable.

No one fuel will be able to displace motor gasoline in the next 20 or more years. Limitations in feedstock availability and, in the case of electricity, limitations due to the range of the vehicles will prevent 100% displacement of motor gasoline. Over the longer term, displacement of gasoline may be possible. In the mean time, it makes sense to continue development of fuels which offer potential GHG reduction and other

environmental benefits.

Major improvements can be expected in the fuel cycles and vehicle technologies of all of the alternatives. We believe that it would be premature at this time to designate any one fuel as the "best". We recommend that vehicle manufacturers and fuel producers be given incentives to reduce the GHG impact of each fuel as much as possible, at every step along the chain of the feedstock to fuel to vehicle miles travelled. This is the best way to achieve the full potential of GHG benefits offered by alternative fuels.

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